CALIFORNIA ENERGY COMMISSION

INTEGRATED ENERGY POLICY REPORT: 2004 UPDATE

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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EXECUTIVE SUMMARY

Over the next several years, California faces significant challenges in ensuring adequate electricity supplies to keep California's lights on during critical peak demand periods. In addition, the state faces regional and local reliability challenges, especially in Southern California. To address these challenges, California must step up its efforts to achieve the goals already established for demand response programs, make better use of its existing fleet of power plants, and move forward aggressively to bring new resources on-line.

California consumers are up to the task ahead; they know how to conserve energy and reduce demand during times of short supplies. As recently as the 2000-2001 electricity crisis, Californians embraced energy efficiency and demand response programs, thereby reducing state demand by approximately 6,000 megawatts, more than 10 percent of peak demand. To meet the coming challenge, consumers must be armed with the tools necessary to shift their energy use away from critical peak periods, when supplies are especially tight.

California must also act now to assure that its long-term energy strategy – the *Energy Action Plan's* loading order – is realized.[1] California's principal energy agencies have been meeting regularly to coordinate activities, programs, and proceedings in critical energy areas.[2] As a result, these agencies have made major strides to implement the loading order strategy. But more must be done.

California's systematic under-investment in transmission has left the state's transmission lines congested, increasing the cost of electricity to consumers and reducing reliability. In addition, inadequate transmission presents a significant barrier to accessing renewable energy resources critical to diversifying fuel sources, slowing California's increasing dependence on natural gas, and helping California meet its environmental goals. The state must significantly alter its approach to transmission planning, not only to keep the lights on and hold down energy costs, but also to advance critical state energy, environmental, and economic policy goals.

In this 2004 update, the *Integrated Energy Policy Report* Committee focused on three areas:

- reliability issues with aging power plants
- transmission planning
- renewable energy development

Near-term Supply and Reliability Concerns

In the *2003 Energy Report*, the California Energy Commission concluded that under average weather conditions, California is likely to have adequate energy supplies through 2009. However, if adverse weather conditions occur in 2006 and beyond, then operating reserve margins could fall below the seven percent needed to maintain system reliability.[3]

Additional analysis undertaken for this *2004 Energy Report Update* indicates that, if significant numbers of aging power plants continue to retire between now and 2008, reserve margins in the state could become dangerously thin.[4] Aging power plant owners may choose to retire these units because they are unable to fully recover their costs during the relatively few hours of the year they can operate. Keeping this capacity available while transitioning from reliance on Department of Water Resources (DWR) contracts to newly constructed plants will prove a daunting challenge.

This summer, California saw the emergence of regional reliability problems, especially in Southern California, associated with increasing congestion on the transmission system. Currently, aging power plants appear to be an important element in addressing congestion on the southern portions of the CA ISO system and assuring that supplies from outside the greater Los Angeles basin can be reliably delivered to load centers.

As many as 10,000 MW of aging power plant capacity is considered to be at risk for retirement by 2008. While it is doubtful that all of these aging power plants will retire, because retiring just a portion of them would likely improve the financial prospects for those remaining on-line, additional steps must be taken to assure that California has adequate supplies over the next few years. The consequences of not taking actions to address potential supply shortfalls from possible retirements would place consumers and businesses at unacceptable risks.

2004 Update Proposed Recommendations

The Committee believes that a combination of actions on the demand and supply sides are necessary to stave off another electricity crisis in the near term.

The state must accelerate its implementation of demand response programs that signal the actual price of electricity to customers during peak demand periods. Peak hours, while they occur for only 50 to 100 hours a year, pose one of California's most significant challenges to ensuring reliable electricity supplies. Rapidly deploying demand response programs in the state is the most effective approach to address peak demand for the summers of 2005-2008. The first order of business for demand response programs should be ensuring that utilities attain the aggressive goals already established by the California Public Utility Commission (CPUC) and Energy Commission.

Simultaneously, the state needs to shore up its electricity supplies, including generation from aging power plants, to maintain adequate reserve margins for peak demand periods and to provide regional and local reliability services. The Committee recommends developing a capacity market to help meet the state's proposed resource adequacy requirements and deliverability standards. In addition, California must maximize its ability to share resources, both inside the state between the investor-owned utilities (IOUs) and adjoining municipal utilities and with out-of-state suppliers.

While pressing for short-term solutions, California must not lose sight of its long-term goals for transmission and renewables.

Transmission upgrades and expansions are critical to ensuring a robust and reliable electricity system. The state must design a comprehensive transmission planning process that is based on a proactive expansion policy and that recognizes the long useful life of transmission assets and their increasing public goods nature. California must also establish a process to plan effectively for transmission corridors well in advance of their need. This will ensure that land necessary for future transmission lines can be identified in government land use plans and acquired by utilities. Finally, California's transmission planning process must address the need for transmission to access renewable resources to meet state policy goals.

To continue the flow of investment in renewable resources in the state, and drive down the costs and push for continued innovation in renewable technologies, California must develop ambitious long-term renewable goals. Progress has been made toward achieving the accelerated goal of meeting 20 percent of retail electricity sales in the state with renewables by 2010. However, unless the state sets out longer-term renewables targets for 2020, important momentum could be lost, short-changing California's consumers by limiting the long-term fuel diversity, and environmental benefits of renewables.

In addition, solar photovoltaic (PV) systems hold promise to enable consumers to help address our peak demand challenges by combining PV with super energy efficiency measures and price-responsive demand programs. The Governor's interest in moving forward with a Solar Initiative presents California with a unique opportunity to leverage investments in PV to achieve important conservation, environmental, and fuel diversity goals.

The following is a summary of the Committee's recommendations that are addressed in more detail in the remainder of the *2004 Energy Report Update*.

Attaining Our Aggressive Demand Response Goals

All municipal and investor-owned utilities should work aggressively to attain the 2007 statewide goal of meeting 5 percent of peak demand through demand response programs.

By January 2005, the CPUC should approve IOU proposals to modify the current tariff design that could expand program eligibility and attractiveness for the summer of 2005.

The CPUC should begin implementing a full-scale rollout of advanced metering systems for smaller customers, and begin developing dynamic rate offerings and load control options for customers as the metering systems become operational.

The Energy Commission should work with Department of Water Resources (DWR), the CPUC, California Independent System Operator (CA ISO), and other water agencies to investigate and pursue all cost-effective load management and demand response programs on these water systems.

Shoring Up Electricity Supplies

The Energy Commission should work with the CPUC and other parties to develop a capacity market to allow flexibility in meeting proposed resource adequacy requirements, including a capacity “tagging” mechanism and tradable capacity rights.

California should re-examine the link between the CA ISO transmission expansion process and local area reliability assessment to ensure that the process stimulates investment in a more robust transmission system, as well as a more rapid transition from dependence on reliability must-run contracts.

The Energy Commission should support the pending petition to allow the utilities to enter into one- to five-year power purchase contracts, as long as these contracts do not discourage developers from constructing new power plants already licensed by the Energy Commission.

The CPUC, the IOUs, and municipal utilities should consider allowing cold standby plants to contribute to reserve margins to provide insurance against low hydro conditions and system contingencies, such as the extended outage of nuclear plants or transmission lines.

Enhancing Supply Management

The Energy Commission, CPUC and all utilities should:

- Establish more closely coordinated planning and reserve sharing among California’s IOU and municipal utility service areas to allow greater sharing of generating resources.

- Pursue all cost-effective seasonal energy exchanges with the Pacific Northwest to satisfy California’s summer peak demand, including needed transmission upgrades to take advantage of seasonal generation surpluses.

- Explore opportunities to use existing pumped-storage facilities more fully, to provide both a more stable base load for existing power plants and valuable peaking power generation during high demand.

Designing a Comprehensive Transmission Planning Process

The Energy Commission, as part of the 2005 Energy Report proceeding, should establish a comprehensive statewide transmission planning process with the CPUC, CA ISO, other key state and federal agencies, local and regional planning local agencies, investor-owned and municipal utilities, generation owners and developers, stakeholders and interest groups, and the public. This statewide planning process should:

- Assess statewide transmission needs for reliability and economic projects as well as transmission to support RPS goals;
- Examine non-wires alternatives to transmission;
- Approve beneficial transmission infrastructure investments that can move into permitting;
- Examine the right-of-way needs for future transmission projects and allow utilities to set aside or bank necessary land for longer periods of time;
- Assess transmission costs and benefits that recognize the 30-50 year useful life of transmission assets, incorporate methods (quantitatively and qualitatively) to assess the long-term strategic benefits of transmission, and use an appropriate social discount rate.

To facilitate transmission for renewables projects, the Energy Commission should step up its participation in the Joint Transmission Study Group on the Tehachapi Wind Resources Area, including initiating corridor planning to facilitate permitting of needed upgrades, and establish a Joint Transmission Study for the Imperial County geothermal area.

The Energy Commission, CPUC and CA ISO should investigate whether changes to the CA ISO tariff are needed to encourage transmission projects necessary to meet Renewables Portfolio Standard (RPS) goals.

Achieving Ambitious Renewable Energy Goals

The state should enact legislation to require all retail suppliers of electricity, including large publicly-owned electric utilities, to meet a 33 percent eligible renewable goal by 2020, using common definitions of eligible renewable energy.

The state should enact legislation that allows the CPUC to require Southern California Edison (SCE) to purchase at least 1 percent of additional renewable energy per year between 2006 and 2020, reaching 25 percent by 2010 and 30 percent renewable energy by 2015 and 35 percent by 2020.

Wind turbines should be repowered to harness wind resources efficiently and prevent bird deaths, and the CPUC should require IOUs to facilitate such repowerings in its pending effort to develop renegotiated Qualifying Facilities (QFs). Local permitting agencies for wind re-powering projects should implement actions similar to those identified in the recent Energy Commission methodology study on mitigating bird deaths.

The Energy Commission should continue to assist the Governor's Solar Initiative to achieve greater market penetration of PV systems in the state through a robust and long-term funding program. This program should help address peak demand challenges by combining PV with super-energy efficiency measures and price responsive tariffs.

The Energy Commission should launch a performance-based PV incentive pilot program in 2005 with $10 million of incentives to enable California to move toward a performance-based PV incentive program.

CHAPTER 1: INTRODUCTION

In this report, the California Energy Commission provides the Governor and Legislature with an update from the *2003 Energy Report,* continuing its focus on upgrading California's energy infrastructure with additional analysis and recommendations on reliability, transmission planning, and renewable energy development.

Key State Agencies Collaborate

In 2003, the state's principal energy agencies developed a common policy vision widely referred to as "the loading order," as articulated in the *Energy Action Plan* and cemented in the *2003 Energy Report*. The loading order calls for optimizing energy conservation and resource efficiency, meeting new generation needs first with renewable energy resources and distributed generation then with clean fossil fuel generation, and improving the bulk electricity transmission grid and distribution infrastructure.[5] The loading order was expressly embraced by Governor Arnold Schwarzenegger in a letter to CPUC President Michael Peevey on April 28, 2004.

This vision is now being carried out through collaborative staff work between the CPUC and Energy Commission in several joint proceedings such as:

- Electricity resource procurement (CPUC R01.10.024 and R04.04.003).
- RPS proceeding (Energy Commission 02-REN-1038 and 03-RPS-1078 and CPUC R01.10.024).
- Energy efficiency and demand response proceeding (CPUC R.01.08.028).
- Distributed generation policy development (Energy Commission 04-DIST-GEN-1 and CPUC R.04-03-09.017).
- Natural Gas Supply and Infrastructure (CPUC R.04.01.025).

Report Development Process and Public Review

This report was developed under the direction of the Energy Commission's 2004-2005 Integrated Energy Policy Report Committee. Beginning in late 2003, the Energy Commission staff began holding meetings with a wide range of stakeholders to gather input for the *2004 Energy Report Update*. Along with these numerous meetings, the Committee held a series of public workshops to gather information and data. Altogether, 14 workshops were held.

Through the process, stakeholder participation was extensive, beginning with a request for comments at the various workshops on reliance on aging power plants, improving transmission planning, and accelerating renewable energy development. Transcripts were made of each workshop, and stakeholders were urged to submit comments for each workshop. Over 200 written comments have become part of the record in Energy Commission Docket #03-IEP-1.

Drawing from the record, the staff drafted the three staff white papers:

- *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements* [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-26_workshop/2004-08-04_100-04-005D.PDF]

- *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond* [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-23_workshop/2004-07-30_100-04-004D.PDF]

- *Accelerated Renewable Energy Development* [http://www.energy.ca.gov/2004_policy_update/documents/2004-08-27_workshop/2004-07-30_100-04-003D.PDF]

These draft documents were released in the summer of 2004, and then followed with three Committee hearings to solicit comments on the staff white papers and ensure that the Committee accurately captured public input to create a substantial record for the *2004 Energy Report Update*.

In drafting the report, the Committee considered public input carefully, sifting through the extensive record and reflecting on current conditions, to develop its various policy recommendations. The Committee's draft report and recommendations will be vetted in a series of five Committee hearings throughout California. The Committee will then revise the report to reflect public input before it is released for the California Energy Commission to consider at its November 3, 2004, Business Meeting.

Report Structure

The remainder of this report is arranged into three chapters:

Chapter 2: Reliability Concerns with Aging Power Plants
Chapter 3: Transmission Planning
Chapter 4: Renewable Energy Development

CHAPTER 2: RELIABILITY CONCERNS WITH AGING POWER PLANTS

Introduction and Background

California has a significant number of aging power plants that may be retired in the near-term because they do not fully recover their on-going fixed costs in the current market, since they operate infrequently.[6] This chapter discusses the reliability concerns associated with these aging power plants, focusing on the years 2004 to 2008.

In the *2003 Energy Report*, the Energy Commission noted that the retirement of aging power plants can affect the state's reserve margins, with estimates of retirement between 4,630 and 7,232 megawatts (MW) from the Energy Commission and CA ISO, respectively.[7] More starkly, merchant generators indicated 10,000 MW could be retired in the near term.[8] Along with contributing this capacity toward reserve margins, some of these aging power plants provide important local and regional reliability services.

Although the reliability implications are critical to address, these aging power plants also have implications for California's dependence on natural gas for electric generation. In recent years, natural gas prices have become increasingly volatile, heightening California's awareness of its growing dependence. In the *2003 Energy Report*, the Energy Commission noted that the state could help reduce natural gas consumption from electric generation by taking steps to retire older, less efficient natural gas-fired power plants and replacing or re-powering them with new, more efficient plants. In addition, the *2003 Energy Report* noted that the aging power plants are more polluting than modern power plants.

Aging Power Plant Study

As part of the *2004 Energy Report Update*, the Energy Commission undertook a detailed study of aging power plants to more closely:

- Analyze the role that individual aging power plants play in maintaining reserve margins and providing local and regional capacity resources and local reliability services,
- Assess the environmental and efficiency implications of continuing to rely on aging power plants, and
- Examine in more detail the range of retirements that can be anticipated over the next few years and better understand the implications of these potential retirements on system reliability.

This study identified 50 aging power plant units to include in an assessment of reliability impacts.[9] The study identified 32 aging units that have a medium to high risk of retiring between 2005 and 2008 because they lack either a reliability must run

(RMR), other contract, or other assured revenue source. Compared with newer combined-cycle plants, aging units have higher fuel costs because of their lower efficiencies. In addition, units have higher operation and maintenance costs because they lack automated controls, meaning higher staffing requirements, and need more frequent maintenance. Without a contract, these units have a limited ability to recover their operation and maintenance costs because they cannot compete effectively in the markets currently open to them during much of the year—primarily the CA ISO energy and ancillary services markets.[10]

Reliability and Reserve Margin Concerns

In assessing the role of aging power plants in California's electricity system, the Committee notes that the aging units under study play the following important roles:

- Provide local reliability services in select areas of the state through the CA ISO's RMR contracts;
- Contribute to regional and statewide reliability by acting as generating reserve margins during periods of peak load, primarily hot summer periods, and in system emergencies; and
- Help alleviate transmission system congestion by offsetting regional transmission congestion, or intertie overloading, with generation at or near load.

Based on the study, the Energy Commission staff identified about 9,000 MW of potential capacity losses by 2008 from aging units with a medium to high risk of retiring as shown in Table 2-1:

Table 2-1

Aging Power Plant Retirements
2004 - 2008 Supply/Demand Scenario

	2005	2006	2007	2008	Cumulative MW
PG&E	326	676	0	2,050	3,052
SCE& SDGE	676	2,152	1,310	1,879	6,017
Statewide Total	1,002	2,828	1,310	3,929	9,069

The statewide supply-demand balance (Table 2-2) shows that even without retirements and including all currently expected new power plant development, generation reserve margins during summer peaks between 2004 and 2008 may become very thin, although these critical periods will be relatively few hours a year. Looking at the historic data, the CA ISO identified a range of 50-100 hours a year when the system load is 90 percent or greater of the absolute peak for the year.[11]

These hours typically occur during extremely high temperatures when combined with other contingencies such as low hydro electricity supplies and other system problems.

Table 2-2

2004 - 2010 Statewide Supply/Demand Outlook

	Aug 2004	Aug 2005	Aug 2006	Aug 2007	Aug 2008	Aug 2009	Aug 2010
Total Supply (MW)	60,157	62,488	63,023	63,350	64,271	63,943	64,035
1-in-2 Summer Temperature Demand (Normal)	55,216	56,365	57,292	58,178	59,158	59,847	60,605
Projected Operating Reserve (1-in-2)	9.9%	11.9%	11.0%	9.7%	9.4%	7.4%	6.1%
1-in-10 Summer Temperature Demand (Hot)	58,572	59,790	60,774	61,713	62,753	63,484	64,287
Projected Operating Reserve (1-in-10)	3.0%	4.9%	4.0%	2.9%	2.6%	0.8%	-0.4%

SOURCE: California Energy Commission -

If all the aging plants in Table 2-1 were retired, under normal weather conditions, reserve margins drop below 7 percent in 2007 and steadily decline through 2008. Under adverse weather conditions, reserve margins would drop to below 7 percent as soon as next summer, 2005 as shown in Figure 2-1 and Table 2-3.

Figure 2-1

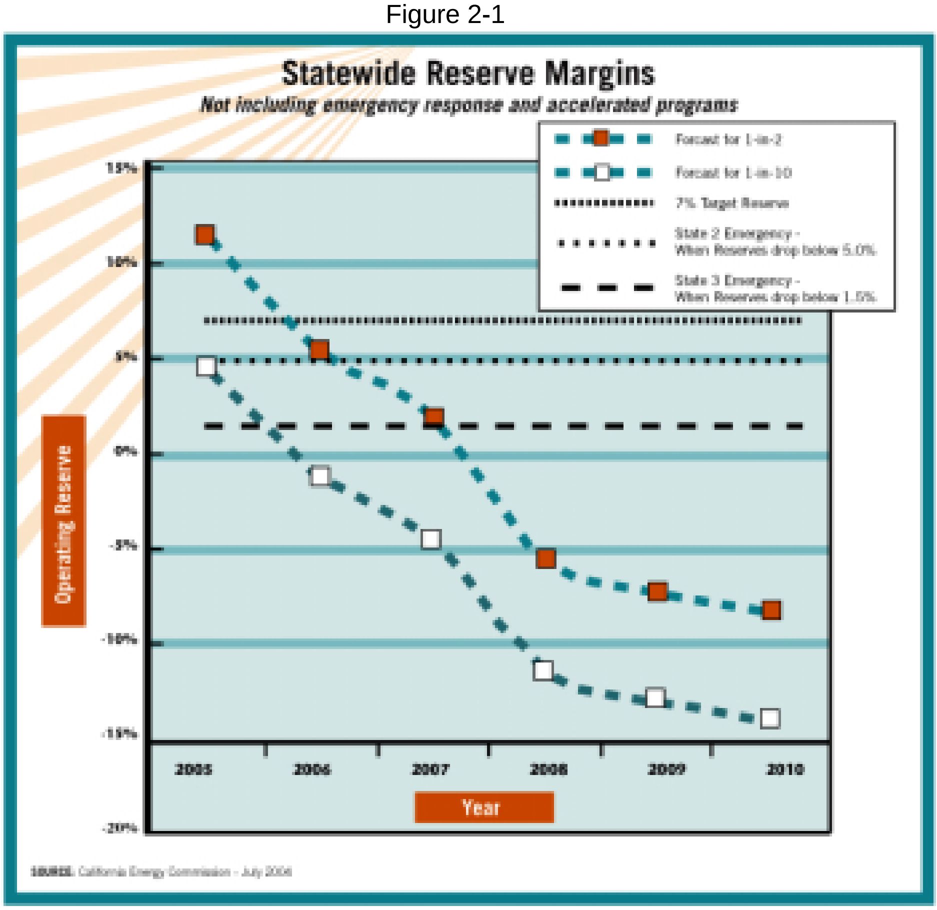


Table 2-3

2004 - 2010 Statewide Supply/Demand Outlook

	Aug 2004	Aug 2005	Aug 2006	Aug 2007	Aug 2008	Aug 2009	Aug 2010
Total Supply (MW)	60,157	62,236	60,133	59,150	56,624	56,296	56,388
Expected High and medium risk	-601	-1,343	-5,023	-1,310	-3,912	0	0
1-in-2 Summer Temperature Demand (Normal)	55,216	56,365	57,292	58,178	59,158	59,847	60,605
Projected Operating Reserve (1-in-2)	9.9%	11.4%	5.4%	1.8%	-4.7%	-6.4%	-7.5%
1-in-10 Summer Temperature Demand (Hot)	58,572	59,790	60,774	61,713	62,753	63,484	64,287
Projected Operating Reserve (1-in-10)	3.0%	4.5%	-1.1%	-4.5%	-10.6%	-12.1%	-13.1%

SOURCE: California Energy Commission

It is unlikely that *all* aging units in the medium and high risk cases will retire or shut down. Since aging units compete with each other, retiring just a portion of the state's aging units would likely improve the financial prospects for those remaining on-line. However, if a substantial number of aging units actually retire, electricity supplies could be adversely affected in the near term.

Although the range of retirements is uncertain, the supply-demand balance for the southern portion of the state, including Southern California Edison and San Diego Gas & Electric, shows that possible retirements have a more serious impact on reserve margins. As indicated in Tables 2-4 and 2-5, under normal weather conditions, inadequate reserve margins in Southern California could cause rotating outages in 2006 and beyond. Yet under adverse weather conditions, inadequate reserve margins could result in rotating outages as early as 2005.

Table 2-4

SCE and SDG&E Service Territories with High Retirement Scenario

2004 - 2008 Supply/Demand Scenario

	8/04	8/05	8/06	8/07	8/08
Total Supply (MW)	27,648	27,744	26,503	25,288	24,018
1-in-2 Summer Temperature Demand (Normal)	25,088	25,610	26,068	26,531	27,002
Projected Operating Reserve (1-in-2)	16.2%	13.9%	2.7%	-7.6%	-17.8%
1-in-10 Summer Temperature Demand (Hot)	26,589	27,104	27,589	28,078	28,577
Projected Operating Reserve (1-in-10)	6.1%	3.8%	-6.2%	-15.6%	-24.8%

Table 2-5

PG&E Service Territory with High and Medium Retirement Scenario
2004 - 2008 Supply/Demand Scenario

	8/04	8/05	8/06	8/07	8/08
Total Supply (MW)	24,958	25,104	24,071	24,166	22,256
1-in-2 Summer Temperature Demand (Normal)	21,404	21,832	22,218	22,549	22,973
Projected Operating Reserve (1-in-2)	16.1%	14.7%	8.2%	7.0%	-3.1%
1-in-10 Summer Temperature Demand (Hot)	22,828	23,284	23,696	24,050	24,502
Projected Operating Reserve (1-in-10)	9.0%	7.7%	1.6%	0.5%	-9.0%

Reliability and resource adequacy concerns in southern California focus on the need to find options to bring in additional supplies in the near term. Although the Energy Commission has licensed over 18,000 MW of power plants since 2000, some 8,000 MW lack financing and have not proceeded to construction (see Figures 2-2 and 2-3). While the near-term need for resources appears to be in southern portion of the state, the vast majority of these plants that have been licensed, but not constructed are in northern part of the state. In the near term, transmission infrastructure additions and enhancements like Path 26 should be a high priority to facilitate greater transfers from Northern to Southern California.[12]

Figure 2-2

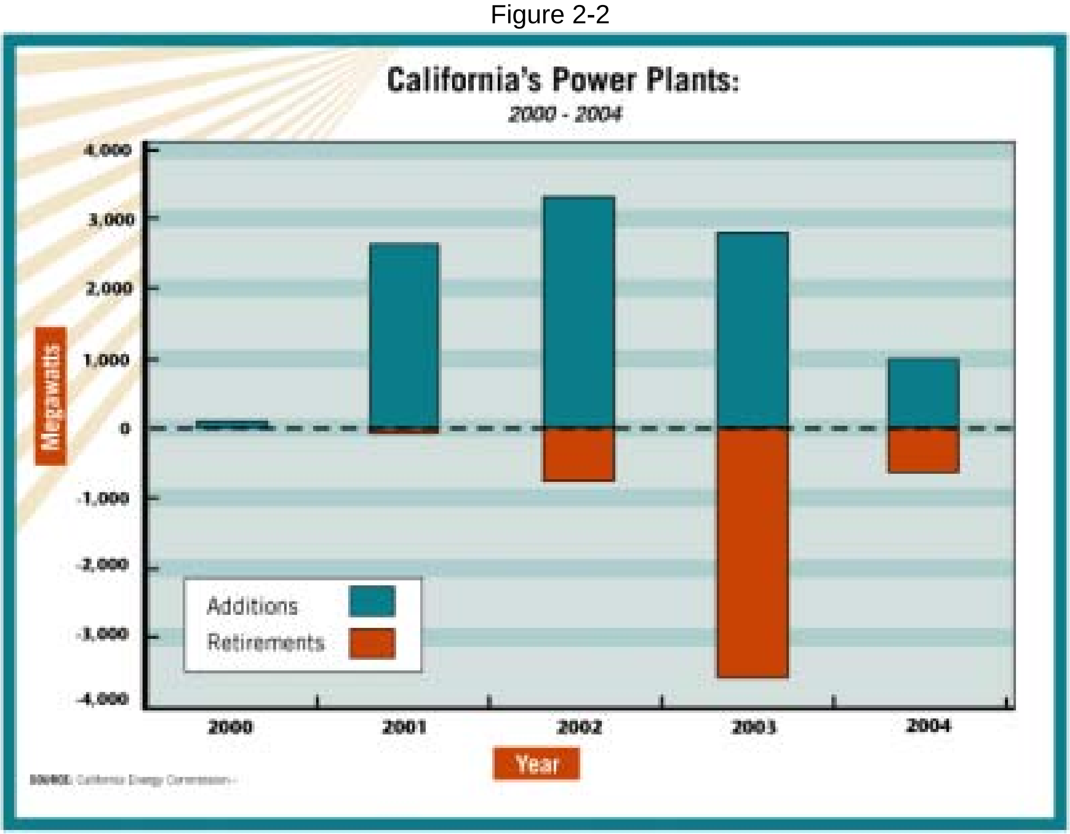
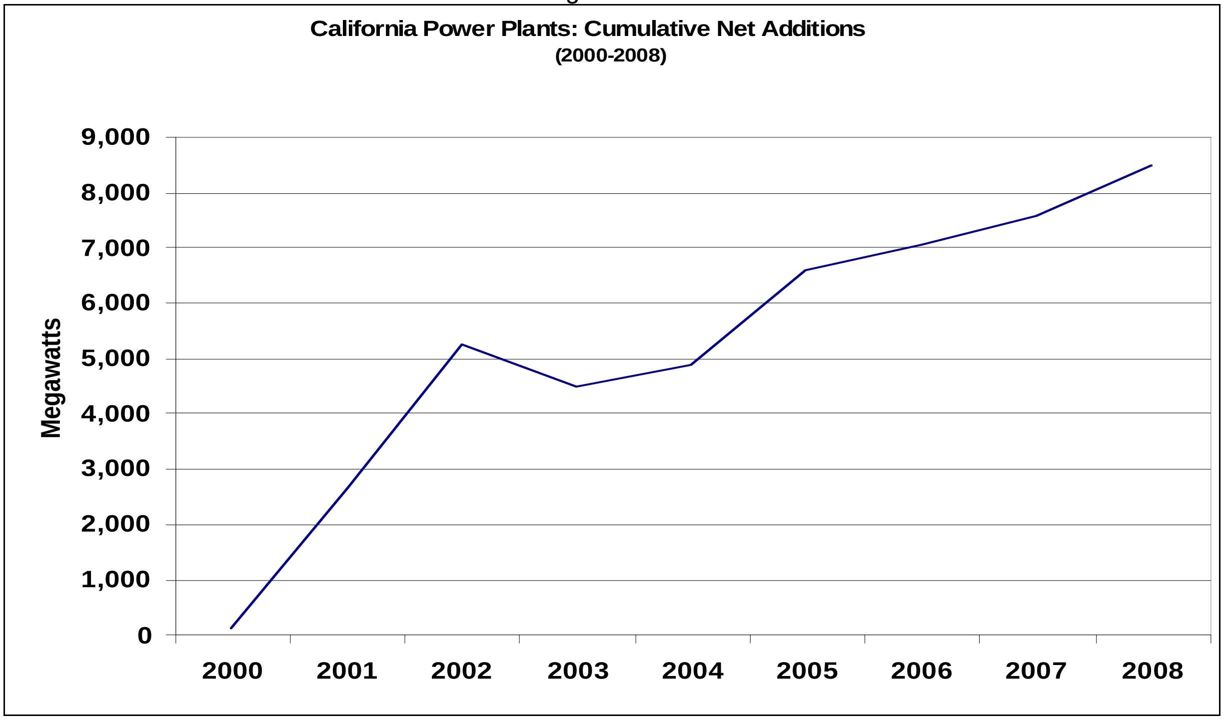


Figure 2-3



The CPUC's recent proposed decision on resource adequacy requirements could improve the prospects for aging power plants if they are able to successfully compete to meet short- and medium-term IOU needs as the Department of Water Resources (DWR) contracts begin to expire. The Committee believes that while resource adequacy requirements may improve the prospects for aging plants to continue to operate, additional policy initiatives will be necessary to forestall reliability problems until replacement resources become available through long-term procurement.

Efficiency and Environmental Concerns

Although the 2003 Energy Report raised both efficiency and environmental concerns associated with continued reliance on natural gas-fired aging power plants, the Committee notes that it is important to examine the specific roles these aging power plants play in the electricity system, and to compare their efficiency and environmental impacts relative to the alternatives for each of these roles.

In general, the Committee notes that many of the aging power plants (30 out of 50) have emission control technologies that are comparable to those of the new combined cycles. Because similar Selective Catalytic Reduction technology is used on the combined cycles and the aging plant's steam boilers, the difference in emissions reflects only the differences in the relative heat rates or efficiency of the two types of power plants.

Aging power plants provide part of operating reserves in peak periods in California, which may occur for 50 to 100 hours per year. Peaking resources must be available when needed. In this role, the aging power plant fleet acts in place of peaking resources such as combustion turbines which are likely to be even less efficient and have even greater emissions. As discussed below, it should be possible to reduce peak loads through demand response programs, or to share reserves among multiple utilities for peak periods, or even to store some of California's off-peak power in existing in-state pumped storage facilities or hydro facilities in the Pacific Northwest. The aging power plants can be used to replace some of the energy from hydro generation in dry years or to replace generation from existing coal and nuclear power plants when those plants have forced outages.

California's newer combined cycles are operating below their design levels, which significantly reduces their efficiency and increases their emissions. Typically, these combined cycles can provide replacement power at lower cost and with fewer emissions than the older technology used in aging power plants, which are primarily steam boilers. However, existing aging power plants can provide backup generating capacity for abnormal events such as a very dry hydro year or prolonged outages, such as when the nuclear power plants are taken out of service while their steam generators are replaced. It would be economically inefficient to build new combined cycles for such standby service, while older units can be placed in cold standby for such contingencies.

These aging power plants are generally well-suited to provide load-following capability to the grid. As discussed in the staff white paper, older technology steam boilers like the aging power plants have a relatively constant efficiency across broad operating ranges while the efficiency of new combined cycle units, though high, drops off substantially at lower operating levels. With that decline in efficiency, emissions rates for the newer plants increase.

Accelerate Demand Response Programs

Demand response programs are California's most promising and cost-effective option to address our near term reliability and reserve margin concerns.

A recent report of the Bay Area Economic Forum compared California's performance in demand response and load management programs relative to other states', ranking California twentieth in the nation.[13] This is a significant underperformance when compared to our worldwide reputation in energy efficiency programs. The report further concluded that California could reduce its peak loads an additional 2,000 MW if it achieved only the 3.5 percent load reduction as the state of Florida.

The Committee believes that the state must aggressively implement comprehensive demand response programs over the next three years. The CPUC, in collaboration with the Energy Commission, has established aggressive demand response goals for California IOUs, calling for 5 percent of bundled customer peak demand in 2007 to be met with various demand response programs.[14] This translates to approximately 1,900 MW for the IOUs and 2,600 MW for the state as a whole by 2007.

In 2004, the IOU demand response availability was approximately 1,500 MW. Table 2-6 shows that California still relies largely on traditional interruptible programs for emergency load relief. The advantage of these programs is that they have been in use for many years, customers are familiar with them, and they have worked well. The disadvantage of these programs is that they require industrial customers to shut down production during times of electricity shortage, such as happened on a regular basis in 2001 during the electricity crisis. Interruptible programs also do not take advantage of advanced communication and control technologies that allow more customers to participate voluntarily in demand response programs in ways that are less intrusive to them. Voluntary demand response programs could mitigate the disruptive effects of interruptible programs to industrial customers or rotating outages on other customers.

Table 2-6

Available Peak Demand Response: Investor-Owned Utilities (2004)

Demand Response Program	Estimated Peak Reduction (MW)
Interruptible / Curtailable	799*
IOU/CPA Demand Bidding	344
Direct Load Cycling	237**
Critical Peak Pricing	25
Voluntary Load Reduction	130
Total IOU	1,535

* 2004 subscription level of 1,113 MW discounted to reflect past program performance
** Discounted from total of 317 MW to reflect past program performance

Source: CPUC monthly report from utilities, R.00-10-002

Currently, California has a number of demand response resources available to it for summer 2004 including: interruptible and curtailable load, demand bidding, critical peak pricing, CPA demand response, air conditioner cycler and Smart Thermostat programs.

Table 2-6 above shows that California still relies largely on traditional interruptible programs for emergency load relief. The advantage of these programs is that they have been in use for many years, customers are familiar with them, and they have worked well. The disadvantage of these programs is that they require industrial customers to shut down production during times of electricity shortage, such as happened on a regular basis in 2001 during the electricity crisis. Interruptible programs also do not take advantage of advanced communication and control technologies that allow more customers to participate voluntarily in demand response programs in ways that are less intrusive to them. Voluntary demand response programs could mitigate the disruptive effects of interruptible programs to industrial customers or rotating outages on other customers.

The Energy Commission and CPUC are working to develop a plan to offer customers a menu of dynamic rates.[15] The Energy Commission has also been working with the CPUC to develop dynamic pricing programs using advanced metering and controls.[16] That effort has focused on two groups of customers: residential and small commercial customers who less than 200 kW in size and large customers greater than 200 kW.

Several thousand residential and small commercial customers have participated in the Statewide Pilot Project, which is a large-scale formal experiment testing several types of dynamic rates and load control technologies. The results show that customers who receive dynamic rates can and do respond by reducing their peak demands, and that doing so is acceptable to them in terms of comfort and rate impact. About 80 percent of customers reduced their bills, and reduction in coincident peak load for residential customers averaged about 12 percent (during a relatively cool summer) for the experimental tariffs used in the pilot. Small commercial customers also showed substantial peak reductions. The experiment is continuing through the summer of 2004.

The next phase in the CPUC proceeding is utility submittal of their “business cases” on implementation of advanced metering for customers with less than 200 kW demand levels. While the demand response effects from dynamic rates could be very large, the actual implementation process (CPUC approval of meters and dynamic rates, installation of meters, and customer education) will probably take at least two years to achieve significant results. Therefore, the short-term impacts will not reflect the large potential over the longer term.

During the 2000-2001 electricity crisis, the state funded the installation of about 20,000 real time meters for customers greater than 200 kW, which greatly expanded the number of large customers who could participate in demand response programs and dynamic pricing. Through the CPUC dynamic pricing proceeding, large customers are being offered a limited number of dynamic pricing options. Although there is a substantial potential from these programs, achievement to date has only been some 25 MW, as shown in the table above. However, Energy Commission and CPUC staffs are continuing to work with utilities and customer groups to improve the dynamic pricing options and demand response from those rates and programs.

Proposed Demand Response Recommendations

In the near term, increases in demand response capability will have to come primarily from larger customers who already have real-time meters and are offered a menu of pricing options and programs. The utilities are proposing a number of changes to the current tariff design that could expand program eligibility and attractiveness for the summer of 2005, with CPUC approval of these plans planned for January 2005.

The Committee recommends significantly increased efforts to achieve existing demand response goals for the summer of 2005 through 2007, and accelerating and expanding demand response goals wherever possible. The state's IOUs should place their highest priority on achieving the aggressive goals already established by the CPUC and Energy Commission. The CPUC should ensure that its current proceeding, focusing on price responsive demand programs for 2005, is calibrated to reaching these goals. The Committee also recommends that the CPUC begin implementation of a full-scale rollout of advanced metering systems for smaller customers, and begin developing dynamic rate offerings and load control options to offer customers as the metering systems become operational.

Proposed Recommendation for Other Load Shifting

In addition, the Committee recommends that the Energy Commission work with the DWR, the CPUC, the CA ISO, and other relevant water agencies and municipalities to identify opportunities to reduce electricity demand related to the water supply system during peak hours. While DWR is the largest single user of electricity in California because of its need to pump massive amounts of water over very long distances and elevations, it currently operates the State Water Project to maximize pumping during off-peak hours and to minimize on-peak pumping based on power and transmission costs, contract delivery requirements and operational or engineering constraints. DWR is also one of the major participants in the CPA's Demand Reserves Partnership program and regularly offers load into the CA ISO's "load drop" market.

While the short-term options for additional peak load reduction from operation of the SWP may be limited, the Energy Commission and the CPUC should work with DWR and other water agencies to investigate and pursue additional cost effective load management and demand response programs on these water systems that may be possible in the longer term. Long-term options may be available that would require engineering and marketing assistance from the Energy Commission or the use of state bonding authority, such as for installation of additional storage capacity to make them cost effective. In addition, the CPUC should consider rate design proposals that would encourage local and regional water agencies to participate in demand response programs.

Resolve Market Issues and Reduce Regulatory Risks

The Energy Commission should work with other parties in the CPUC's procurement proceeding, in particular the resource adequacy phase, to develop proposals for capacity markets and explore how these proposals could be used to meet short-term potential supply-demand shortfalls, especially those resulting from the retirement of aging power plants in the state.

Develop Capacity Markets

Developing a capacity market in California could provide an effective means of reducing uncertainty while giving power plant owners and developers clear signals as to their ability to compete in the present and future electricity markets. Capacity markets can provide a useful framework to help achieve resource adequacy goals in a cost-effective and flexible manner. Properly designed, a capacity market can compensate providers of needed capacity from any resource, and ensure that the generator can meet any “qualifying” requirements established for resource adequacy.

Ultimately, well-established capacity markets would allow aging power plants to compete with other existing generation and new power plant construction. Aging plant owners maintain that the location of their facilities near load is of higher value than generation more remotely located. A capacity market, in combination with resource adequacy requirements and deliverability standards, should send proper signals to the market about the value of these generating units.

The CPUC’s proposed decision on resource adequacy requirement takes a significant step forward in stabilizing California’s electricity market and providing adequate future supplies. The CPUC proposes to explore developing a capacity market in California, which the Committee believes will be an important component of the overall resource adequacy framework. Any approach to capacity market design, though, must be consistent with the resource adequacy requirements, while providing the opportunity to meet those requirements flexibly and cost-effectively.

The CPUC also proposes to develop deliverability standards to ensure that resources counted toward adequacy targets are available in the local areas where needed. To the extent deliverability requirements can ensure that resources are available where they are needed, deliverability requirements can supplement and ultimately replace the current system of reliability must-run contracts in meeting local reliability requirements.

The Committee believes that some form of “tagging” system that enhances the liquidity of capacity resources can help reduce the costs of a capacity obligation. Tagging concepts have been proposed that would shift capacity from a bilateral contract between generator and utility or other load serving entity, such as an energy service provider or community choice aggregator, to a market with standardized products and liquidity. Such a market would help accommodate a core/non-core market structure and Community Choice Aggregation programs.

The Silicon Valley Manufacturing Group (SVMG) has taken a leadership role in developing such a capacity tagging proposal. Their current proposal is a good first step, but will need considerable refinement over time, particularly to accommodate changing market design. The Committee notes that the CPUC has announced a capacity markets conference for October 4-5, 2004 in San Francisco, jointly sponsored with CA ISO and Electricity Oversight Board.

Proposed Capacity Market Recommendations

The Committee recommends that the CPUC, Energy Commission, and all stakeholders follow the broad policy principles below in developing a capacity market:

- Capacity markets should be targeted to meet resource adequacy requirements, and should include applicable deliverability criteria.
- Initial steps toward implementation of a capacity market should be targeted to meeting near-term capacity requirements. The Energy Commission staff white paper suggested that some aging plants could compete quite effectively in such a market.
- Capacity made available in a capacity market must be verifiable. A capacity "tagging" mechanism building on the approach suggested by the SVMG is one way of accomplishing this.
- Tradable capacity rights can help address uncertainties related to load and responsibility for meeting resource adequacy requirements, mitigating the "stranded asset" scenario that has played prominently in the core/non-core debate.

Multi-Year Utility Contracts

Multi-year contracts could provide additional assurance that the investor-owned utilities can secure reserve requirements and reliability resources as the supply demand situation tightens in the next few years. Such multi-year contracts could include aging power plants, to the extent they supply reliability services and provide cost-effective capacity resources, as a bridge to bringing on new generation.

The CPUC limited the utilities to one-year contracts under the approved short-term procurement plans and deferred considering mid-term contracts to the long-term procurement proceeding. Pacific Gas & Electric (PG&E) and SCE have filed petitions to modify the CPUC decision, which would allow them to execute mid-term commitments (up to five years) pursuant to their adopted short term procurement plans. In addition, PG&E and SCE have also requested authority for such contracts as part of their long-term procurement filings. PG&E has indicated that it would use this authority to execute contracts with existing power plants for up to three years.

On August 16, PG&E, TURN, and the CA ISO sent a letter to the CPUC requesting that the CPUC provide the utility with the flexibility to procure power now to meet its customer demands through mid-term contracts. These entities were concerned that current limitations hinder the utility's ability to manage long-term market risk and expose ratepayers to the risk of rising prices. They further concluded that such arrangements "may provide generation owners with enough revenue certainty to forestall a shut-down of marginal, but necessary, generation facilities."

While the Committee also wants to forestall such shut-downs of necessary generation capacity, it does not want these commitments to replace long-term commitments to new resources, particularly projects already licensed by the Energy Commission.

The Committee recommends that the CPUC support the pending petition of PG&E, TURN, and the CA ISO to allow the utilities to enter into limited numbers of 1-5 year power purchase contracts as long as these commitments act as a bridge rather than a barrier to additional new resources.

Cold-Standby Plants as Contingency Reserves

One possible method of reducing costs of maintaining reserve margins is to allow cold-standby plants to be used as contingency reserves. These plants would remain shut down but fully staffed during most of the year, so that they could be called upon to start up with advanced notice, typically six weeks to three months, to provide capacity during known times of shortages. By reducing maintenance and operating costs to minimal levels while in cold-standby, these plants could provide a cost-effective alternative to maintaining plants that run, even though they are seldom used except in the rare supply emergency.

Planners and control area operators are generally aware months in advance of the effects of low-hydro conditions on the ability to meet peak summer loads, and could call upon cold-standby plants to startup during late spring and early summer, to be available during the high demand periods during July through September. Similarly, when a nuclear unit is scheduled for refueling or its steam generator is to be replaced, a cold-standby plant could be restarted to substitute for the unavailable nuclear generation.

The Committee encourages the CPUC, CA ISO, IOUs, and municipal utilities to consider using cold standby plants to provide contingency reserves. These plants can remain dormant through much of the year, at minimal cost, and restart with as little as six-eight weeks' notice when planners know a generation shortage may occur.

Transition Away From Reliability Must Run Contracts

The CA ISO and California's utilities perform extensive annual studies to determine what power plants are necessary to ensure that reliability criteria are met, considering their locations near load centers and the reliability services they can provide. The individual power plants most critical for local reliability are awarded RMR contracts. Where multiple units could meet these reliability requirements, an open bidding process is used to identify the most cost-effective set of resources that can meet those minimum generation requirements. In some cases, however, only a limited number of resources can meet these reliability needs, and cost-based contracts are signed with those specific generators.

For example, the City and County of San Francisco is located on a peninsula with limited transmission interconnections to the rest of the California grid. As a result, the existing power plants at Hunters Point and Potrero are both currently designated as RMR units. These plants must continue to operate until the CA ISO determines that they are no longer necessary for local area reliability. The RMR contracts provide revenue assurances to the plant owners, but also tend to limit their ability to participate in other energy markets where they may be able to secure higher prices for generation.

RMR contracts have been considered an expensive and temporary measure, and both the FERC and the CPUC have encouraged the utilities to pursue alternatives and reduce the need for these contracts. In some cases, IOUs can reduce the need for RMR contracts by upgrading their transmission systems, and thereby reducing the obligations for RMR contract payments. Once the transmission investment occurs, some units likely will lose their RMR contracts and not be required to operate.

Over the last several years, SCE has pursued a variety of transmission upgrades to reduce the number of RMR contracts in Southern California. PG&E also is pursuing transmission upgrades to reduce RMR requirements. For example, the Jefferson-Martin transmission upgrade, along with associated transmission enhancements in San Francisco, should eliminate the need for the RMR contract at the Hunters Point plant.

However, delays in getting transmission upgrades on-line may create or worsen regional or sub-regional reliability problems. Earlier this summer, CA ISO entered into an RMR contract with Reliant so that the Etiwanda units could be returned to service. Last fall, Reliant, pursuant to settlement agreements, held an auction offering the capacity from its Etiwanda facility, but no one submitted a bid. After an SCE transmission upgrade was delayed, though, because the components were diverted to repair damage from the Southern California wildfires last year, the CA ISO found that power flows in the Los Angeles Basin were being unnecessarily constrained by congestion without the Etiwanda facility or transmission upgrade.[17]

Congestion costs have been an ongoing issue for the CA ISO grid. The Path 15 interconnection between Northern and Southern California is perhaps the most visible example, as exemplified in the 2000-2001 power system failures. These system failures were exacerbated by the inability to move power between the two areas of the state. In another example, when the CA ISO examined the need for additional transmission in the SDG&E area, the utilities in the southern California transmission zone (SP 15) were estimated to have incurred nearly $35 million in congestion-related costs over a nine-month period in 2003-2004. The extent to which congestion continues to occur on the southern California system was graphically illustrated by evidence provided by the CA ISO to the Committee during the August 26, 2004 workshop.

This summer, the CA ISO has raised issues about worsening transmission congestion in the Southern California region, and especially on the transmission lines feeding the Los Angeles Basin. In a June letter to the CPUC, the CA ISO raised major concerns that SCE's procurement practices were not adequately considering local reliability needs and that the utility was procuring an excessive amount of power that could not be delivered into Southern California because of congestion.

On July 8, the CPUC adopted D.04.07.028, which addressed the CA ISO concerns about a "relative disconnection between the resources that are scheduled and the ones required to serve load in the SP 15 area."[18]

The CPUC directed the utilities in general to consider local reliability needs in their procurement plans rather than relying upon the CA ISO and/or RMR contracts. While the CA ISO noted that problematic congestion may exist on the grid in the near future, including areas in Northern California, the CPUC did not directly apply the results of its decision beyond Southern California at this time.[19] However, it directed all the IOUs to minimize total costs, including reliability and all known and reasonably anticipated CA ISO-related costs (including congestion, re-dispatch, and must-offer costs).

The CA ISO and SCE are adopting protocols to implement the CPUC decision, which will require the CA ISO to publish information on both known and reasonable congestion and CA ISO costs associated with procurement options.[20] The CPUC plans to revisit how its decision was implemented and the cost impacts later this year. SCE has raised concerns about the compatibility of the CPUC decision on reliability with long-term procurement requirements outlined in Assembly Bill 57. This law calls for the CPUC to reduce the regulatory risks associated with utility procurement decisions by replacing after-the-fact reasonableness reviews with an upfront review and approval process. The Committee believes that harmonizing the CPUC reliability decision with the AB 57 requirements (and FERC's policies requiring open, non-discriminatory access to the bulk transmission grid) will be challenging.

Proposed Recommendations to Transition Away From Reliability Must Run Contracts

The Committee recommends that California re-examine the linkage between the CA ISO transmission expansion process and the Local Area Reliability Study (LARS) and RMR efforts. The Committee is concerned that, despite the CPUC approving over $2.34 billion in transmission investments over the last several years, congestion appears to be a persistent and growing problem on the CA ISO grid.[21] While it is unclear exactly why more transmission fixes to congestion have not emerged from the transmission expansion and LARS efforts, the Committee remains concerned that California continues to systematically under invest in transmission infrastructure.

The CPUC has enunciated a goal of transitioning away from the RMR contracts to long-term procurement framework that considers local reliability needs combined with a viable deliverability component to its proposed Resource Adequacy Requirement. The Committee believes that, given the critical reliability role of the RMR units, such a transition needs to be carefully and smoothly executed over the next few years.

Enhanced Supply Management

Increasing the flexibility of the existing generating resource base through transmission upgrades and other options could greatly reduce the potential shortages of generating resources in coming years. California's operational history shows that the so-called "super peak" from air conditioning demand on very hot days seldom simultaneously hits all areas of the state. More often, one particular region hits very high peaks, stressing the available generation margin in that area, while nearby areas have relatively milder weather and generation surpluses.

For example, over the 10-year period from 1993 to 2002, the sum of the non-coincidental peaks of the utilities in the CA ISO control area was between 800 MW to 2,800 MW greater than the highest annual peak load on the CA ISO system as a whole.[22] While California needs to be prepared to generate supply on a reliable basis even during a heat storm throughout the West, there is considerable value in enhancing the ability to transfer power to the local area or region that is stressed by high temperatures or outages of local generation.

However, because of transmission congestion, control area operators are very limited in their ability to take advantage of surpluses in other regions by importing more power, and therefore must rely on local generation to meet the peaks.

Transmission bottlenecks typically occur at the seams between the CA ISO control area and those of the three publicly-controlled control areas (SMUD, LADWP, and IID). For example, the transmission systems of SCE and LAWDP are only weakly interconnected at two locations.

Preliminary transmission system analysis shows that retirements within the Los Angeles Basin sub-region could reduce the capability of importing power into the area, as well as potentially reduce generating reserve margins to unacceptable levels.[23] Reliability concerns in this sub-region could be reduced by a greater ability to rely upon LADWP's resources in a system emergency.

The state has more than adequate amounts of power in the low-load periods, especially at night. California utilities and generators have some options for shifting power supplies from off-peak to on-peak periods, such as through use of pumped-storage facilities. While the options may be limited, they would not only reduce the number of power plants needed to meet day-time peaks, but could also increase the overall efficiency of the generating sector by increasing baseload operations and decreasing load-following and peaking operations, and thus reduce natural gas use and air emissions as well.

In the past, California utilities contracted with Pacific Northwest utilities for significant amounts of capacity exchange, which benefited both regions. Throughout the 1980s and early 1990s, policy makers in the Western region put significant efforts into nurturing these relationships. With deregulation, though, California utilities began to reorient their procurement to very short-run transactions through the Power Exchange, straining relations with the Pacific Northwest. The relationship was further strained during the California electricity crisis when California's price spikes rolled throughout the regional supply markets, and the Pacific Northwest attempted to erect a "fire wall" between itself and California. Many of the existing exchange contracts dissolved in the ensuing litigation.

Proposed Supply Management Recommendations

The Committee recommends that the Energy Commission work with utilities, the CPUC, and other agencies to identify cost-effective projects that would increase transfer capability between the transmission system in the CA ISO control area and the three other California control areas. This increased connectivity would provide flexibility to control area operators in matching generation to load, and could reduce the number of power plants needed to meet total system-wide demand. For instance, the "needle peaks" from air conditioning loads on very hot days in mid- and late-summer seldom occur in all areas of the state at the same time.

With increased connectivity, control area operators would have greater flexibility to import power from cooler regions that have generation surpluses. As discussed in Chapter 2, many factors have led to the under-investment in California's transmission system, and a number of policy steps are needed to address this critical problem.

The Committee also recommends that the Energy Commission establish a joint planning effort to take advantage of the complementary utility systems in California and the Pacific Northwest more fully. Historically, wholesale power transactions have provided significant benefits to both regions in the form of exchange contracts. The Committee recommends that the California energy agencies identify broad regional policies that would provide guidance to IOUs and others about the developing exchange contracts of this sort with Pacific Northwest entities.

The Committee recommends that the Energy Commission work with CA ISO, CPUC, and California's other control area operators to identify and alleviate transmission barriers to the sharing of generation reserves, eliminating any bottlenecks between the control areas posed by policies that excessively constrain flexibility to use resources for reliability purposes.

In addition, the Committee recommends the Energy Commission establish a joint planning effort to use existing pumped-storage facilities in the state more fully.

Pumped storage facilities can pump water to higher locations in the off-peak periods, providing additional baseload demand through the night, and then produce power during peak usage in the afternoon. PG&E has a pumped storage project at Helms, while LAWDP and DWR have similar opportunities associated with water deliveries over the Tehachapis. PG&E, SCE, or SDG&E may be able to contract with DWR and/or LADWP for use of their facilities.

CHAPTER 3: TRANSMISSION PLANNING

Introduction

The *2003 Energy Report* called for major improvements and upgrades in California's transmission infrastructure. It recommended that the state establish a collaborative planning process to bring forward needed transmission projects in a timely and effective way and provide California with a more robust and reliable transmission system.

As part of the *2004 Energy Report Update*, the Energy Commission began implementing that recommendation, engaging the CA ISO, CPUC, utilities, and other stakeholders in a series of workshops to address planning issues. By bringing together this diverse group of key stakeholders in dialogue several times, the Committee identified a number of long-term needs and strategies to improve transmission planning in the state. In particular, stakeholders emphasized the need for early public participation in the planning process.

The success of a state-wide transmission planning effort will depend to a significant extent on our ability to engage the active participation of local government, public interest groups, and the citizens who live in areas where these infrastructure investments are being considered. Other state and federal agencies affected by or involved with transmission planning and permitting will also need to actively participate.

Although progress has been made in addressing transmission concerns since the *2003 Energy Report* was adopted, California currently lacks a systematic, statewide approach to transmission planning, which would help address critical energy and environmental policies. This chapter discusses the Committee's recommendations for improving the state's long-term transmission planning.

Background

Before electricity restructuring, the IOUs and municipal utilities who did transmission planning could integrate electricity generation and transmission investments so that both were timed and brought on-line to ensure a reliable electricity system. As vertically integrated utilities, the CPUC regulated transmission investments and rate recovery for IOU projects.

Since restructuring, the financial regulation of IOU investments within the CA ISO controlled transmission network, is now carried out solely under FERC jurisdiction. In early September, a California appellate court unanimously agreed with SCE that FERC has pre-empted the field of the regulation of interconnection to the bulk transmission grid. The decision nullified a CPUC order to SCE that it finance transmission network upgrades near Tehachapi rather than look to wind developers to pay for network improvements (there was no dispute about the developers' obligation to pay for lines to the first point of interconnection). Although the decision is subject to appeal and its full ramifications remain unclear, it is an abrupt reminder of the desirability of harmonizing state and federal transmission policies.

In the restructured electricity market, the CA ISO operates the IOU transmission lines in the state and conducts transmission system planning with the IOUs under a FERC approved tariff. This planning process begins when the IOUs submit their annual plans to the CA ISO. The CA ISO conducts a stakeholder process that considers load growth and constrained transmission paths before recommending projects for approval by the CA ISO Board of Governors. The CA ISO and IOUs then submit projects to the CPUC for regulatory approval.

Currently, though, the CA ISO transmission planning process covers only the transmission systems of the state's IOUs, which account for about 75-80 percent of the transmission system. In 2002, the passage of Senate Bill 1389 gave the Energy Commission responsibility to conduct a comprehensive assessment of the electricity and natural gas system, including transmission. Under this authority, the Energy Commission initiated a long-term, collaborative process in 2003 with a broad coalition of stakeholders, building upon the CA ISO annual transmission planning process.

Several shortcomings beset transmission planning in California. One of the principal deficiencies is that the state lacks a comprehensive statewide transmission planning process that is forward-looking and involves all of the relevant market participants and stakeholders, including the 30 percent of the transmission grid not subject to the CA ISO process. Another inadequacy is that current methodologies to evaluate the costs and benefits do not explicitly recognize the long-lived nature of transmission assets—typically a 30- to 50-year useful life—and instead focus on a five-year assessment, recently expanded to 10 years. This inappropriately discounts the long-term benefits of such projects. In addition, many of the benefits that transmission projects have actually provided the state and its electricity ratepayers over the last three decades are completely unrecognized in cost-benefit methodologies presently used to evaluate proposed projects.

Collaborative Long-term Transmission Planning

California must develop a seamless process for planning and permitting transmission. A state planning process should identify needed transmission infrastructure investments, consider the non-wires alternatives to transmission lines, and approve those projects that provide benefits to California. Projects deemed of benefit could then move into the permitting phase. This would allow the alternatives analysis required under California Environmental Quality Act (CEQA) in the permitting process to focus on alternative routes for transmission lines and mitigation measures. This framework could greatly reduce the redundancies in the current process, where alternatives are raised at multiple stages in planning and permitting for transmission.

As described by the CA ISO Market Surveillance Committee:

> Although there are large uncertainties, a proactive and coordinated planning process will account for the interactions, lumpiness, piece-meal policy relying primarily on generation-initiated upgrades. However, the potential harm to consumers associated with under-investment in transmission is far greater than the potential harm associated with over-investment. As such, we recognize that even an imperfect transmission planning process that actually improves the network is better than a dysfunctional process that makes no investments at all.[24]

The planning process must be coordinated with the relevant state and federal policy and regulatory agencies, the CA ISO, investor-owned and municipal utility transmission owners, and the various power plant developers, stakeholders, and members of the public. The Committee proposes that state government initiate a comprehensive, statewide transmission planning process as part of the CA ISO's current grid management plan and the Energy Commission's *2005 Energy Report* process. Important objectives should be:

- Reform cost-benefit methodologies to better reflect the long-lived nature of the investment, the broad dispersion of benefits beyond the sponsoring utility's ratepayers, and the difficulty of quantifying strategic benefits.
- Assess statewide transmission needs for reliability and economic projects as well as transmission projects necessary to achieve statewide policy goals such as the Renewable Portfolio Standard.
- Approve beneficial transmission infrastructure investments that can move into permitting.
- Examine the statewide corridor needs for future transmission projects and allow utilities to sets aside or bank necessary land for future use.
- Provide for early examination of transmission alternatives in the planning phase, so that the environmental review in the permitting phase can more appropriately focus on routing alternatives and mitigation measures.

Establish a State Transmission Corridor Planning Process

The state has no formal process to plan for transmission corridors well in advance of their need so that land necessary for future transmission lines can be set aside by utilities.

To facilitate corridor and right-of-way banking within state- and federally-controlled lands, the Committee recommends that the Energy Commission and CA ISO, in collaboration with the CPUC and stakeholders, develop a statewide coordinated process for corridor planning. Stakeholders should include the California Department of Parks and Recreation, U.S. Forest Service, Bureau of Land Management, investor-owned and publicly owned utilities, Native American tribes, the public, and city, county, and regional planning agencies. Corridor planning should include mechanisms that ensure state, regional, and local land use concerns are assessed together as a part of a long-term coordinated strategic transmission planning process.

In addition the Committee recommends that the state develop a policy for designating and banking utility corridors and rights-of-way, including multiple use infrastructure (e.g., natural gas or water pipeline) corridors. In addition, the Energy Commission and CPUC should investigate current limitations on the utilities' ability to acquire and hold lands for longer periods of time.[25]

Improve Assessment of Transmission Costs and Benefits

Throughout the *2004 Energy Report Update* process, the Committee explored improvements that are needed in the evaluation of the costs and benefits of transmission investments including:

- The need to capture the long, useful lives of transmission assets, which remain in service for 30 to 50 years or more.
- The need to reflect broadly distributed benefits rather than assume that they are confined to a sponsoring utility's ratepayers or shareholders.
- The need to explore various methods that quantitatively and qualitatively capture long-term strategic benefits, such as insurance against unexpected adverse events, price stability mitigation of market power, and potential for increased sharing of electricity resources.
- The use of an appropriate social discount rate to assess costs and benefits of transmission investments.
- The consideration of non-wires alternatives in the transmission planning phase of the project, rather than waiting for the permitting process.

Transmission Assets Have Long Economic Lives

Transmission projects have very long economic lives, staying in service for 30 to 50 years and beyond. The timeframe for evaluating the costs and benefits associated with transmission investments must be longer than the five to ten years currently used in determining the need for transmission projects.[26]

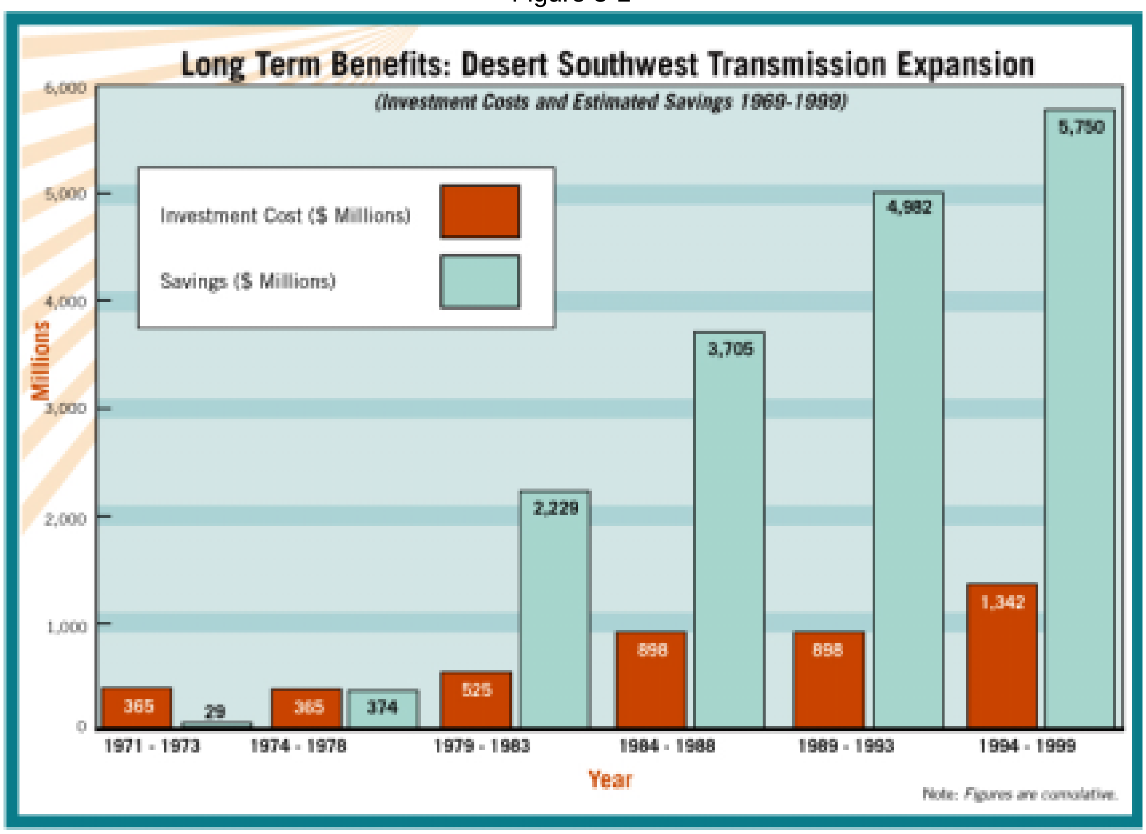
The Committee recommends that the benefits of transmission projects be accurately captured over their 30- to 50-year useful life and fully represented in the analyses that determine which transmission investments best meet California's needs. The Committee also recommends changes to Section 1003(d) of the Public Utilities Code to ensure that the full costs and benefits of projects, including difficult to quantify strategic benefits, are considered in a reformed planning and permitting process.

Strategic Benefits of Transmission Projects

Transmission planners now recognize that many existing bulk transmission projects provide strategic benefits that were not foreseen or were not evaluated either quantitatively or qualitatively in the planning and permitting processes. These benefits include insurance against contingencies during abnormal system conditions, price stability and mitigation of market power, the potential for increased reserve resource sharing, environmental benefits, reduction in generation infrastructure needs, and achievement of state energy policy objectives in commercializing renewable resources.

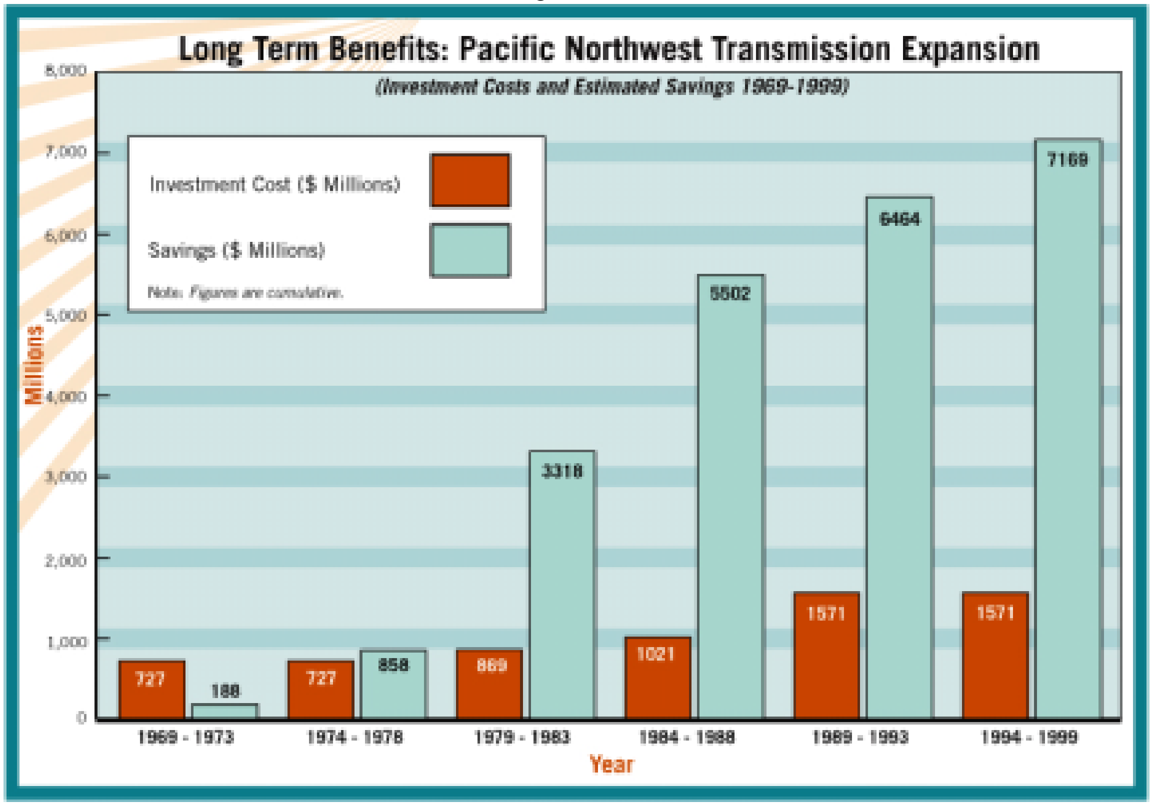
As shown in Figures 3-1 and 3-2, transmission interconnections to the Pacific Northwest and the Desert Southwest over the past 30 years have provided benefits well in excess of their costs. Many of these benefits were not calculated as part of the projects' economic evaluation when the projects were approved because they are difficult to measure and monetize. It is important to develop appropriate methodologies for quantifying as many of these strategic benefits as possible.

Figure 3-1



Source: Consortium of Electric Reliability Technology Solutions. October 2003, *Planning for* California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations. Consultant Report, publication number 700-03009, [www.enjergy.ca.gov/reports/2003-10-23_700-03-009.PDF]

Figure 3-2



Source: Consortium of Electric Reliability Technology Solutions. October 2003, *Planning for* California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations. Consultant Report, publication number 700-03009, [www.enjergy.ca.gov/reports/2003-10-23_700-03-009.PDF]

In the past, imports from surrounding states have provided important insurance against contingencies. For example, in 1985, power imports offset the loss of 1,200 MW when a reheat steam piping failure kept the Mohave Generating Station off-line approximately four months. Also in the mid-1980's, power imports offset the Palo Verde Nuclear Plant's unplanned outage that resulted from a Nuclear Regulatory Commission order to address steam generator issues. This outage represented a loss of approximately 3,600 MW in generating capacity to the Desert Southwest area and 1,000 MW to California.

Imports from out-of-state provided important benefits in stabilizing California electricity prices in the past. For example, during the 1970s oil embargo, California saved more than $100 million per month through shutting down in-state oil-fired plants and importing power from out-of-state non-oil-fired plants. In addition, above-average amounts of attractively priced hydro imports from the Pacific Northwest during periods of wet weather have resulted in substantial cost savings in the state. California saved over $900 million in 1984, which was more than the total investment in the Pacific Intertie up until that year.[27]

Seasonal exchanges and environmental exchanges between California and the Pacific Northwest, as discussed in the previous chapter, have provided for reserve sharing. These sharing arrangements have resulted in fewer power plants being constructed in the West than would have been necessary if each region relied solely on its own generation to meet demand.

While some of the strategic benefits of projects cannot be easily quantified, there are qualitative aspects that should be recognized and presented to decision makers. Decision makers can use this information to make fully informed judgments about the expected present and future value of transmission projects. In the future, all strategic benefits (qualitative and quantitative) of transmission projects must be fully included when evaluating proposed projects, so that decision makers may correctly weigh a project's costs and benefits.

Social Discount Rate for Transmission Planning & Evaluation

The Energy Commission believes using a social discount rate is an appropriate approach for valuing the long, useful life and the public goods nature of transmission projects. The costs and benefits of transmission lines under the restructured market are no longer limited to a utility or its retail customers, as they were when utilities were vertically integrated. The costs of transmission upgrades are now spread among all users of the CA ISO grid through transmission access charges. The benefits of these transmission investments cannot be denied to any retail customer or generation owner, and as a result, transmission lines have increasingly become a public good.[28]

However, the current discount rate used to evaluate transmission projects at the CA ISO and CPUC is based on the utility industry's opportunity cost of capital, which arbitrarily shortens the period over which benefits accrue. The commitment to invest in transmission assets must weigh the costs and benefits to society over the full useful life of these capital-intensive projects. Doing otherwise biases the decision against investment.

Social discount rates are used for the economic appraisal of public projects in other sectors such as transportation, water resource development and land-use. For example, the Energy Commission's cost-effectiveness tests for building standards uses a three percent discount rate that reflects a real (inflation-adjusted), after-tax rate that is more reflective of a social discount rate.

The Committee recommends using a social discount rate, comparable to that used for our buildings and appliance standards, for evaluating the costs and benefits of transmission investments in a state transmission planning process.

Non-Wires Alternatives to Transmission

An important element of a state transmission planning process is appropriate consideration of non-wires alternatives to transmission. To date, non-transmission alternatives have not been considered early in the transmission planning process and are instead delayed until the permitting process. This late consideration has proven disruptive and inadequate. During the Committee workshops for this report, regulatory authorities, industry, and the public agreed that waiting until the permitting process is too late for full or fair consideration of transmission alternatives.

Early consideration of options to a transmission project would provide all parties with the most complete information about the need for a transmission line in a timely manner. If affected stakeholders participated in this process, then the best transmission or non-transmission alternatives would likely move forward to the permitting process.

The Committee recommends that the Energy Commission, in collaboration with the CA ISO, CPUC, and other stakeholders, explore the best approach for examining non-transmission alternatives in the statewide transmission planning process.

Transmission Needs to Meet Renewables Portfolio Standards

The acceleration of the state's RPS has highlighted the importance that transmission plays in the development of renewable resources. The development of remote renewable resources requires substantial investments in new or upgraded transmission facilities.

Transmission interconnection issues for renewable resources located in concentrated areas such as the Tehachapi Wind Resource Areas and Imperial County's Known Geothermal Resource Areas are complicated by the number of developers of renewable resources competing for limited transmission capacity and their limited ability to finance large transmission investments. As discussed in the next chapter on renewable resources, providing for timely and adequate transmission projects will prove critical to meeting the state's ambitious renewable energy goals.

The Committee proposes the following recommendations to facilitate the timely development of transmission to bring renewable projects on line:

- The Energy Commission should step up participation in the work being done by the Study Group for Phased Tehachapi Transmission Development in CPUC proceeding I.00.11.001, Phase 6, led by SCE and the CA ISO.
- The Energy Commission should work with stakeholders to identify corridor or right-of-way studies to ensure effective and efficient permitting for the Tehachapi Wind Resource Area. Stakeholders who should be included in corridor planning for Tehachapi include the CPUC, SCE, LADWP, PG&E, renewable energy developers, military bases, local planning agencies, and interested public.
- The Energy Commission and CPUC should establish a Joint Transmission Study Group for Imperial County's Known Geothermal Resource Areas with municipal and investor owned utilities, renewable developers, Department of State Parks & Recreation Department, and local and regional planning agencies.

In addition, there is a growing recognition among California policy makers that transmission investments to meet RPS goals present a new kind of transmission project for the state. The current CA ISO tariff includes provisions that allow the CA ISO Board to determine if a transmission addition or upgrade is needed to promote economic efficiency or maintain system reliability.[29] Since the tariff does not contain an explicit provision for a need determination for projects which meet RPS goals, the Energy Commission, CPUC, and CA ISO should investigate whether changes to the tariff are needed.

CHAPTER 4: RENEWABLE ENERGY

Introduction and Background

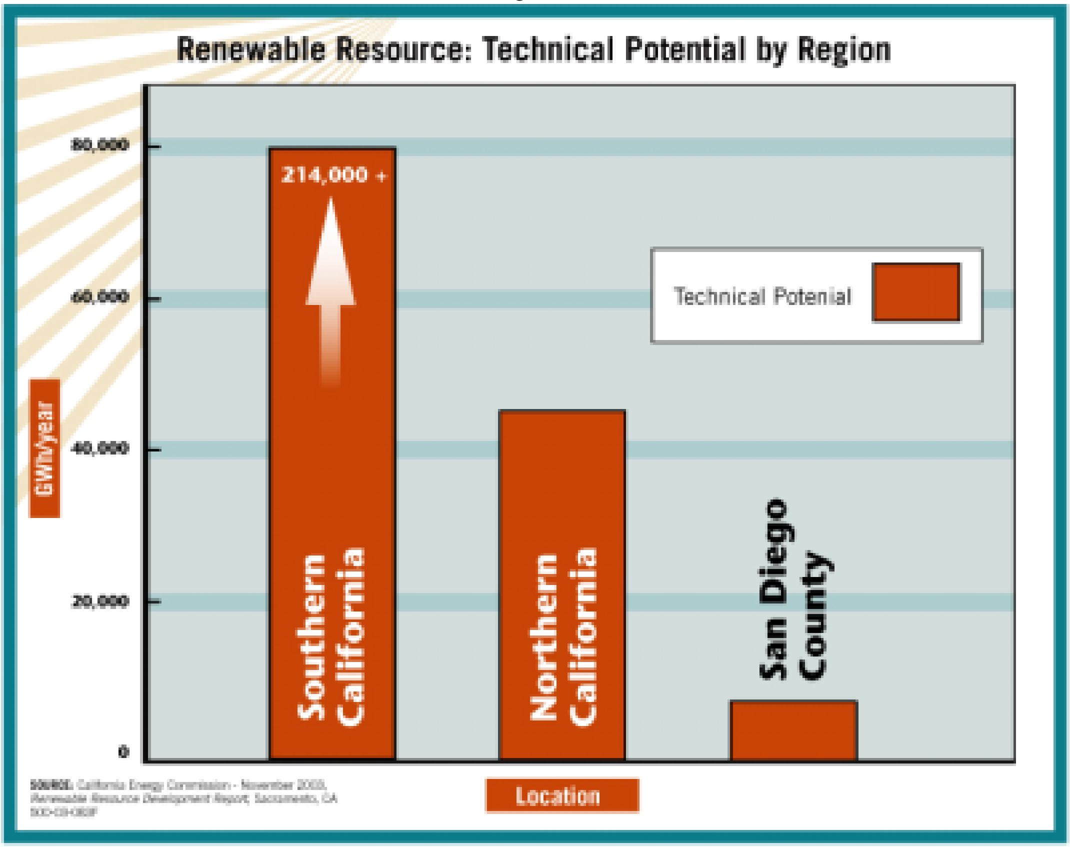
Renewable energy is an important priority in the state's loading order, and as noted in the *2003 Energy Report*, the RPS is the centerpiece of the state's strategy for diversifying the electricity system. This chapter discusses California's RPS, along with several recommendations for changing the program and accelerating renewable energy goals.

The state's RPS program enjoys broad public support, with nearly nine in ten surveyed Californians supportive of doubling the use of renewables over the next 10 years.[30]

As implemented by the CPUC and Energy Commission, the RPS requires all investor-owned utilities to increase their portfolio of renewable resources by at least 1 percent of sales every year to reach the target of 20 percent renewable resources by 2010. Senate Bill 1078 directs publicly owned utilities to develop RPS programs consistent with the Legislature's intent, taking costs and the goal of environmental improvement into account. As outlined in the legislation, the CPUC and Energy Commission have different complementary responsibilities, and as a result collaborate closely to administer the RPS (for details on the RPS, see the staff draft white paper *Accelerated Renewable Energy Development*, Appendix B, publication number,100-04-003.)

California enjoys abundant renewable resources, but they are unevenly distributed across the state, with over 80 percent of the resources located in Southern California, including in the Tehachapi Mountains and Imperial Valley. (See Figure 4-1, Renewable Resources: Technical Potential by Region.) Yet, even though Southern California has significant potential, the transmission infrastructure is not available to deliver renewable resources to other areas in the state with fewer renewable resources.[31]

Figure 4-1



Source: California Energy Commission*, Renewable Resource Development Report*, October 2003.

The Energy Commission, CA ISO, CPUC, and other stakeholders are collaborating to address transmission constraints within California, as well as inter-state; work will continue through 2005 and beyond. Transmission necessary to access wind resources near the Tehachapi area and geothermal resources located in Imperial County presently appears to be the highest priority. The state needs to act now to make critical infrastructure investments to ensure the timely development of these renewable resources to meet California's growing electricity needs.

Notwithstanding the transmission constraints, more ambitious goals, in particular post-2010 targets and accelerated goals for SCE are also essential to maintain momentum in long-term investment and technological advances in renewable energy.

Current Progress on Renewables Portfolio Standard

At the end of 2003, IOUs appeared to be on track for meeting the state's accelerated RPS goals of 20 percent renewables by 2010. Since the end of 2001, the IOUs have held interim solicitations that have increased their procurement of renewables by about 4,000 Giga watt hours a year (GWh/year), or over 2 percentage points each, without RPS funds; these funds were established to pay for above market costs of renewables.[32] However, facility operators from several projects who have sold the

IOUs energy under these interim contracts have received financial support from the Energy Commission's previous renewable incentive programs.

Both PG&E and SDG&E have released their first formal RPS procurement solicitations. However, SCE will not hold a solicitation this year, as it has indicated that it will reach 20 percent renewables in 2004, six years ahead of schedule.[33] As required by law, the IOUs cannot count large hydro as a renewable resource for meeting the RPS.

Unlike the IOUs, the state's publicly owned electric utilities have adopted widely divergent renewable energy programs and some count large hydro as a renewable resource, despite its exclusion in SB 1078. For example, Los Angeles Department of Water and Power (LADW) has a renewable target of 20 percent by 2017, but has not decided whether or not to include large hydropower. Without large hydro, LADWP's renewables program is currently about 1.5 percent of its retail sales. On the other hand, Sacramento Municipal Utility District's (SMUD) program has a 20 percent goal by 2011, excluding large hydro. Currently without large hydro, SMUD's renewable resources are about 7 percent of its current retail sales.

The Imperial Irrigation District (IID) has a renewable goal of 20 percent by 2007, but its program includes large hydropower. Without large hydro, the IID retail sales of renewables are12 percent. Imperial Irrigation District has stated that it intends to reach its goal, 20 percent by 2007, by adding a geothermal plant by 2007, although IID does not own the renewable energy certificates (RECs) associated with the electricity from the project.[34] The IID's market claim, for procuring electricity without RECs, is contrary to the accounting approach that the Western Governors' Association endorsed,[35] as well as California's Power Content Label Program.[36]

Some smaller utilities have indicated that they anticipate difficulty complying with the RPS because of their contractual obligations, small load, slow growth rates, and the lack of locally available renewable resources.

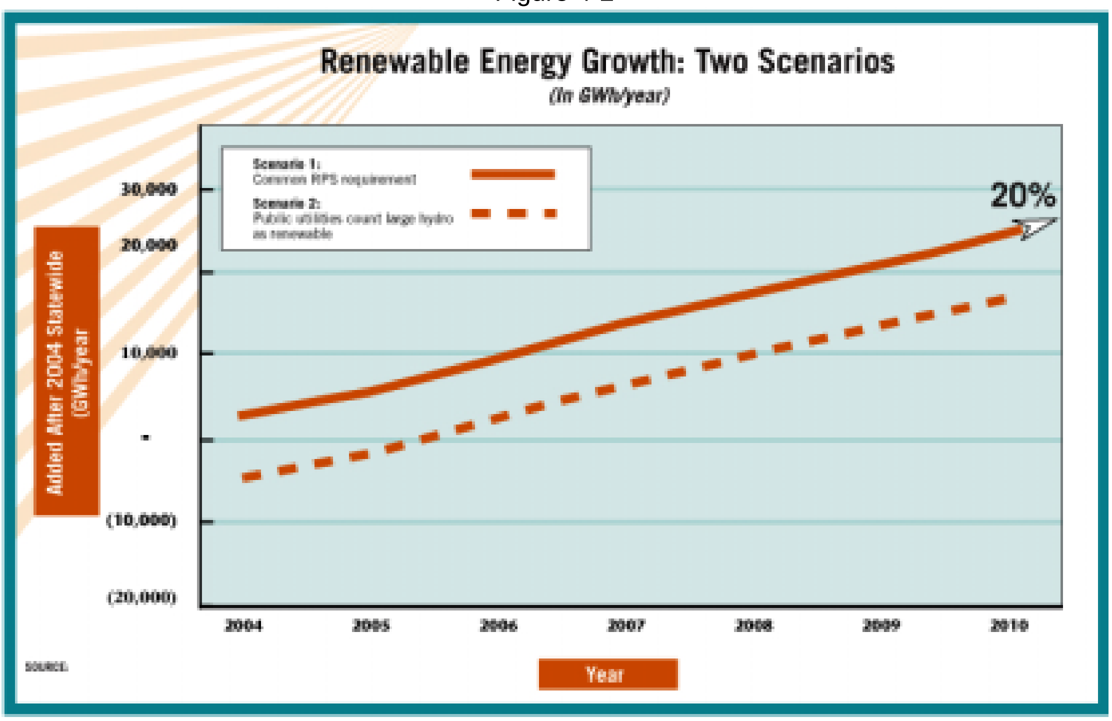
Develop Ambitious RPS Goals

The Committee believes it is important to set ambitious RPS goals for the post-2010 period. Such goals are needed if California is to maintain the momentum for renewable energy development, continue investments and innovations in technology, and drive costs down for renewable energy. Governor Schwarzenegger has previously indicated support for accelerating the RPS goal to reach 20 percent renewables by 2010 and 33 percent by 2020.[37]

To meet the statewide accelerated RPS, California must add approximately 25,000 GWh of new eligible renewables by 2010. While the IOUs are on track to meet this target, bringing the municipal utilities into the program, especially LADWP, will likely prove crucial to achieving the statewide goal. Given the breadth of the public support for RPS, the Committee expects most municipal utilities to be enthusiastic participants but believes consistent definitions between programs are important to maintain the public's confidence. For example, if large hydro were counted for IOUs under SB 1078, the corresponding statewide goal for 2010 would more logically be 40 percent rather than 20 percent.

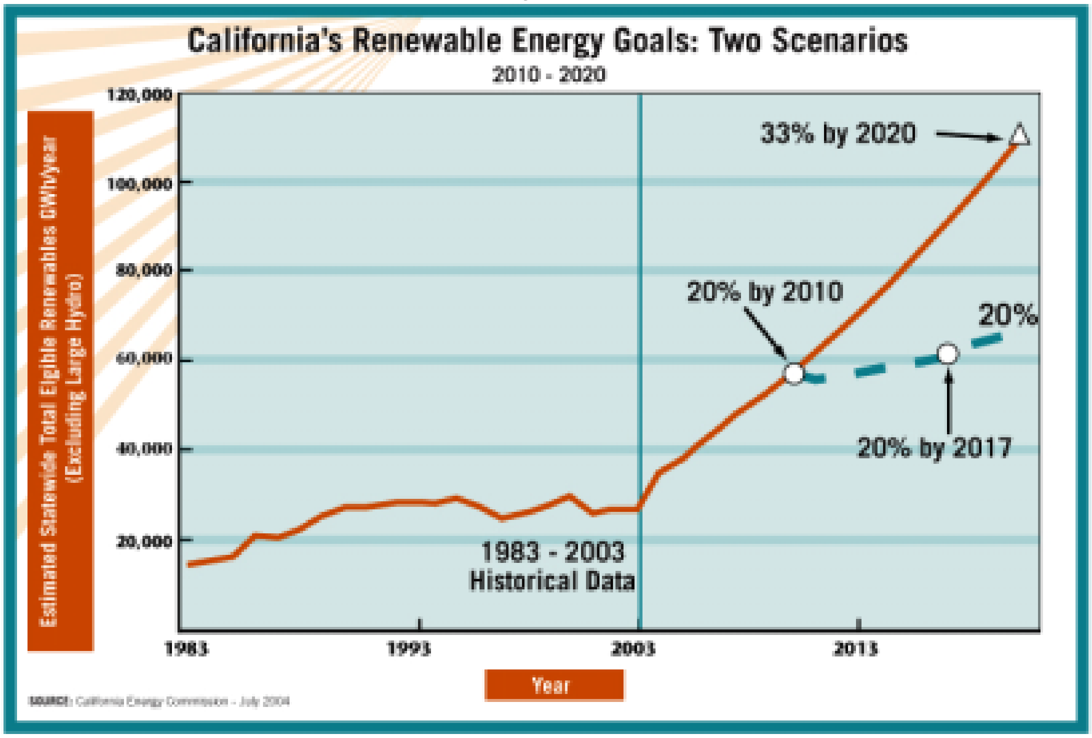
Along with Figure 4-2, the two different scenarios in Figure 4-3 illuminate the need for a statewide program for all retail sellers to participate. The Committee recognizes, though, that some small utilities may face significant challenges to comply with the RPS goals and recommends a variance process for such circumstances.

Figure 4-2



Source: Draft Staff White Paper: Accelerated Renewable Energy Development, California Energy Commission, June 2004.

Figure 4-3



Source: Draft Staff White Paper: Accelerated Renewable Energy Development, California Energy Commission, June 2004.

This recommendation is needed because long-term goals with a sufficient funding source will encourage the long-term private investments in technology and other innovation, bringing them to commercial-scale application, driving down the costs, which require long lead times. The technology for low-speed wind turbines, for example, is not expected to be widely available until 2011 or 2012.

In terms of expanding development beyond 2010, without more ambitious goals, the Figure 4-2 illuminates how little progress California will make in expanding future renewable energy development. Further, without more ambitious goals for 2010 and beyond, the utilities will have little incentive to continue their investments in renewable development, and the momentum necessary to reduce costs and push technological innovation would be stymied.

The Committee's recommendation would correct this problem, and allow California to take advantage of the abundance of renewable resources in the west and further the state's goals to reduce our growth in natural gas dependence.

Individual Utility Targets

The Committee recommends that California IOUs with the greatest renewable potential should have a higher RPS target beyond 20 percent by 2010.

With over three-fourths of the technical potential within the SCE service area, SCE started the RPS with a base of 15 percent for 2001 and 17.56 percent in 2002.[38]

Through its first interim solicitation 2003, SCE increased its retail sales from cost-effective renewables to 18.11 percent, without needing additional RPS funds.[39] SCE held an additional interim solicitation last summer, but has yet to bring forward contracts with winning bidders for the CPUC to approve.[40] Further, SCE will not hold an RPS solicitation this year under the state's first formal RPS solicitation, as the utility has indicated that it will reach 20 percent renewables target in 2004.[41] In fact, depending on the results of last year's interim solicitation, SCE may be able to maintain its 20 percent goal without having to issue any RPS solicitations for several years.

The Committee believes that a new target for SCE will help accelerate renewable energy development statewide, and although SCE has raised concerns that a higher target will increase its ratepayers costs, the current regulatory framework adequately insulates SCE's ratepayers for any above market costs through PGC funds. In the past, SCE has shown strong leadership in this area and has taken pride in being the largest purchaser of renewable resources in the United States. The Committee believes SCE's continued leadership will be vital to achieving the state's long-term objectives to commercialize its renewable resources and to promote fuel diversity in the electricity sector.

To minimize the uncertainty regarding SCE's participation in accelerating California's RPS, the Committee recommends state legislation to allow the CPUC to require SCE to purchase at least 1 percent of additional renewable energy per year between 2006 and 2020, reaching 25 percent by 2010, 30 percent by 2015, and 35 percent by 2020. For PG&E and SDG&E, which started the RPS with a base of 12.3 percent and 1.8 percent respectively, the Committee believes that the 20 percent target by 2010 is reasonable and should not be adjusted at this time.

SCE's new target should be implemented under the existing RPS structure. SCE's procurement plans, annual procurement targets, and least-cost-best-fit criteria should be revised to reflect at least 1 percent of additional renewable energy per year between 2006 and 2020 to reach the new target.

Barriers to Accelerated Renewable Resource Development

Transmission expansions will be needed in the Tehachapi and Imperial County areas to take advantage of some of the most promising sources of renewables. The current transmission interconnection process for new generation is based on single location power plant development. As a result, this planning model does not fit the characteristics of renewable resources in remote areas. The risk of planning transmission on a plant-by-plant basis is development of a suboptimal system. In contrast, the risk of planning for long-term renewable development provides for a more optimal transmission system, but assumes that multiple developers bring their plants into operation on a given schedule.

Because the results from the first formal RPS solicitations will not be final until the end of the year, it is unclear how many projects in the Tehachapi area or Imperial

County will qualify for transmission upgrades in the near-term under the state's present transmission planning process. Future solicitations will likely include bids from these areas, but there is substantial risk in waiting until the RPS solicitations are final and contracts signed to begin planning and approving the future transmission upgrades to accommodate additional winning contracts. A proactive approach to transmission planning for renewables development is necessary to avoid a classic chicken-and-egg dilemma. Phased development plans for transmission upgrades to accommodate renewable resources in remote areas like Tehachapi and the Imperial Valley must be developed and will be essential to meeting RPS goals in a timely and cost-effective manner.

Unbundled Renewable Energy Certificates

Trading unbundled RECs may be an effective way to assist utilities with fewer local renewable resources to meet the state's renewable energy goals in the future, although unbundled RECs are not currently allowed in California's RPS program.

A REC typically represents the environmental attributes of renewable energy as a separate commodity from the electricity, and for this discussion, the term is used in its broadest definition to mean the "renewable attributes" of a given unit of renewable-based generation, as distinct from the underlying electrical energy.[42] A REC may be "bundled" and sold together with the underlying electricity or a REC may be unbundled and the renewable attribute sold separately. Currently, RECs procured for RPS compliance must remain bundled with the associated renewable electricity.[43]

Senate Bill 1478 (Sher) has been sent to the Governor for signature. The bill requires the Energy Commission, in consultation with the CPUC, to establish the definition of a renewable energy credit to:

- ensure compatibility with standard contract terms and conditions and
- protect the interests of ratepayers.[44]

Unbundled RECs represent a potential advantage for California because they could reduce the need to add transmission lines, or relieve transmission congestion, to help meet renewable energy goals. Yet this potential advantage will depend on the location of the renewable resource and whether transmission lines are available to transfer the electricity. Although RECs can help utilities transfer "renewable attributes" between utilities, RECs cannot eliminate the need for transmission infrastructure to access renewable energy or meet RPS targets.

Even with these potential transmission constraints, though, unbundled RECs may be a reasonable means for electric service providers and community choice aggregators to comply with the RPS. Unlike the IOUs and municipal utilities, electric services providers and community choice aggregators are typically small entities, who may lack a guaranteed revenue stream or credit backing for long-term power purchase agreements. Electric service providers and community choice aggregators may prefer to enter into short-term electricity contracts, with relatively small financial commitments and the flexibility to respond to market changes. For these two groups, then, unbundled RECs may be an appropriate compliance option. Through their collaborative work, the CPUC and Energy Commission will develop rules for both groups to comply with RPS goals in 2005.

The CPUC and other parties, however, have raised a possible disadvantage to this approach: whether allowing unbundled RECs would create environmental justice issues. For example, if an IOU procured unbundled RECs from a new wind facility outside its service territory, along with matching fossil fuel-based electricity generated locally, to serve its load, then the renewable energy would not result in local air quality benefits.

The CPUC also indicated that allowing unbundled RECs for the RPS could invite market manipulation, or double counting. If RECs were to become a feature of the RPS, the Committee notes, then safeguards will be needed to ensure that a RPS contract for bundled renewable electricity is not stripped of its electricity. The Western Renewable Energy Generation Information System accounting system, currently under development, can help to prevent double counting.[45]

Through the ongoing RPS proceedings, the CPUC and Energy Commission collaborative staff will further investigate the advantages and disadvantages of incorporating unbundled RECs into the RPS for IOUs as well as for electric service providers and community choice aggregators.

Re-powered Wind Facilities

Re-powering California's aging wind facilities could result in roughly 470 GWh/year of incremental wind energy.[46] Because of rising concerns in recent years about the need to reduce bird deaths associated with wind facilities, many of which use antiquated technology installed over 20 years ago, re-powering of wind facilities in California has been hindered. For example, neither re-powered nor new wind facilities in the Altamont area will receive permits until planning officials are confident that steps have been taken to prevent bird mortality.

The Energy Commission funded a multi-year research project to better understand factors associated with bird fatalities in the Altamont Pass.[47] This report identifies a series of mitigation measures designed to avoid, reduce, and offset impacts caused by existing and future wind turbines in the Altamont Pass Wind Resource Area. The research concluded that the most effective solution to reduce bird mortality may be to replace the currently numerous small turbines with fewer, larger turbines, especially if turbines are installed on towers that allow a blade clearance of 29 meters above ground to avoid bird flight paths. The precise effect that the re-powering program will have on bird mortality is unknown and will require post-construction studies to document an actual reduction. Also, these research results should aid the siting process of any new turbines, with a primary goal to install new turbines in locations and arrangements that will result in fewer bird deaths than in the past.

New wind developments and existing developments shown to have high bird fatalities could employ similar research methodology to determine high collision risk factors and avoid high collision risk locations. Doing so will likely result in a reduction of bird fatalities, improve public perception of wind technology, and encourage more energy capacity to be sited in California.

Another barrier to wind re-powering is the current limitations on federal tax incentives for these projects. Federal Production Tax Credits (PTC) provide much needed financial incentives for re-powering of wind; however, provisions in the U. S. Tax Code (Section 45) that prevent wind re-powering projects from qualifying for PTC have had a chilling effect on re-powering decisions. This provision states that re-powered facilities with an existing standard offer contract are only eligible for the PTC if the contract is "amended" such that any wind generation in excess of historical norms is either sold to the utility at its current avoided costs or else sold to a third party.[48] Despite a CPUC June 2003 Decision, endorsing a TURN goal to require IOUs to conduct “prompt negotiation to resolve…a stalemate around re-powering of wind facilities,”[49] progress has not been made. The PTC, which expired in December 2003, has not yet been extended, although it is still under consideration by Congress. Removal of the re-powering clause in the U.S. Tax Code along with extension of the PTC funds would improve prospects for wind re-powering and other renewable development.

The Committee supports re-powering of wind turbines to more efficiently harness wind resources and mitigate or prevent bird deaths and is hopeful that the CPUC's declared intent to develop renegotiated contracts will serve to break the existing logjam that is impeding re-powering.[50] The Committee also recommends that local permitting agencies for wind projects implement the actions identified by the Energy Commission study to prevent and mitigate bird deaths from wind turbines.

California’s Solar Programs

The Energy Commission’s PV incentive program, also known as the Emerging Renewables Program, is oversubscribed, straining administrative and financial resources.[51] The program has been extremely successful in bringing about PV development in the state, supporting over 9,600 PV installations representing nearly 38 MW to date. Another 7,000 applications requesting funding will represent an addition 33 MW of PV installations.[52] However, more robust and long-term funding of PV programs needs to be provided in the next year.

Without significant changes in program design or increased funding level, the Energy Commission’s current incentive program in the IOU service territories cannot be sustained at current subscription levels. In the last 1.5 years, the Energy Commission has encumbered almost 5 years worth of funding for PV as well as re-allocating funds from other Renewable Energy Program areas. Last year alone, the

Energy Commission provided $50 million in rebates to customers to install PV systems.

In addition, the CPUC Self-Generation Incentive Program provides an additional $125 million per year in rebates for larger PV and other distributed generation systems.[53] In 2004, the demand for rebates for PV system installations had dramatically increased, with applicants reserving $228 million. Although Self-Generation Incentive Program incentives over the last several years have brought about 114 installations of large PV systems, representing 21 MW of PV currently installed, the current over-subscription in this program cannot be sustained.

The immediate funding crisis for the Energy Commission's PV program would be addressed by Assembly Bill 135 (Reyes and Campbell) passed in the final days of the 2004 legislative session, which has been sent to the Governor for signature. The bill authorizes the Energy Commission to spend up to $60 million of the Renewable Resources Trust Fund, to be collected between 2007 and 2012, for emerging renewable systems. This bill provides "stop gap" funding for approximately six months, at current program activity level.

The CPA and DGS coordinated a solicitation for bids where private parties may own, finance, and install PV systems on state facilities, provided that the electricity is sold to the state at a price that does not exceed the price that would have been paid to a utility. Given current prices of PV systems relative to the price of electricity paid by the state, the private parties who bid in this solicitation would need to receive funding from the Emerging Renewables Program or Self–Generation Incentive Program, and may take advantage of tax credits and depreciation, to help finance the PV systems.

In addition to the problems of oversubscription, current rebate programs may not be the most effective way to ensure effective design, placement, and maintenance of PV systems to maximize their output. The Energy Commission's Renewables Committee has directed staff to focus on developing a pilot performance-based incentive program by January 2005, using the results of the pilot test to inform development of a long-term strategic plan for the Emerging Renewables Program. Also, the CPUC has proposed lowering the incentive level offered by the Self-Generation Incentive Program to better track Energy Commission incentive levels and is expected to issue a decision later this year.

Performance-Based Incentives

The current PV incentive programs in California provide an up-front buydown of capital costs. Performance-based incentives provide a payment for measured kilowatt-hours of production and are tied directly to system performance.

Performance-based incentives have the potential to provide greater assurance that systems will function well because PV owners are likely to put pressure on installers and marketers to ensure that their systems perform. This promotes greater cost-effectiveness of public goods charge incentives for distributed generation PV in terms of long-term energy generation per dollar of incentive support.

Performance-based incentive programs have achieved tremendous success in Germany. The German model uses a “feed-in” law that requires the utilities to purchase PV generation at rates that have led to a significant number of installations of performance-based systems. Incentive programs can also mix funding tied to capacity with funding tied to energy performance. PV programs in Pennsylvania and Massachusetts are examples of a mixed capacity-and-performance model.

The Committee supports performance-based incentive programs for PV. A workshop to discuss further details of the pilot program is planned for September 2004. There are a number of questions and issues regarding the design and administration of a performance-based incentive program in California. These include what the proper incentive level should be, how best to collect performance data from each system, will performance-based incentives result in better PV system performance, and the appropriate frequency and duration of performance payments to program participant.

Later this fall, the Energy Commission’s Emerging Renewables Program will revise its guidebook and establish the rules for the pilot performance-based incentive program. Results from the pilot will be used to evaluate and shape a performance-based incentive PV program going forward to achieve a sustainable PV market in California.

The Governor’s Solar Initiative

The Governor has indicated strong support for development of an expanded solar initiative in California, targeted at residential applications in new home construction and retrofits in existing homes. In support of these ongoing efforts to encourage the use of PV and bring down installed costs, the Energy Commission will continue to assist the administration’s efforts to explore options that encourage the use of PV on new energy-efficient homes, including market incentives, time-differentiated rate tariffs, builder mandates, innovative business models, and other mechanisms to expand the penetration of PV in California’s residential sector. To achieve the penetration levels being discussed, such as a million solar homes and 50 percent of new homes, the Committee believes a viable business role for the utilities will likely be important to the success of any solar initiative.

The regions in the state where new home growth is occurring, such as the Central Valley and the inland areas of Southern California, are also areas where heavy usage of air conditioning contributes to growth in peak demand. Recent surveys show overwhelming support for solar energy on California homes and businesses, including 82 percent support for a goal of 15 percent of new homes starting in 2006.[54] Installing PV on new residential construction can be valuable to utilities, as PV production generally aligns with peak demand. When peak load is reduced by customer-owned PV generation, it provides benefits for all customers. In addition, at expanded levels of market penetration, reduction in peak demand from PV could help relieve pressures on the existing generation system and help to create additional fuel diversity in California's electricity mix.

The level of financial incentives for PV systems going forward needs to be carefully crafted to help reduce the cost of PV over time. As demand for PV increases, economies of scale in production, manufacturing, retailing, and installation should bring down costs, and financial incentives should be scaled down until they are no longer be necessary. This approach has been followed in Japan, where prices for PV dropped 35 percent from 1999 to 2003. In 2002, the level of subsidy available for PV had been reduced to about $0.75 per Watt. At the end of 2003, cumulative installed PV systems in Japan totaled 640 MW.[55]

The Energy Commission encourages continued progress in developing the Governor's solar initiative. In addition to expanding the market for PV in new and existing homes, the use of PV for commercial applications may also provide for near-term cost-effective deployment of PV technology.

Net Metering

Net metering has been an important element of California's efforts to grow the PV market. Net metering allows a customer's meter to spin backwards when the amount of energy generated by the system exceeds the amount consumed. Combined with time-of-use rates, net metering means that the utility credits the customer at a higher rate for excess electricity generated in the afternoon than the utility charges for electricity consumed in the evening. As a result, net metering can provide an important incentive for customers to install and maintain performance of PV systems.

Assembly Bill 58 (AB 58, Chapter 836, Statutes of 2002, Keeley) expanded the individual project size and assured the availability of net metering up to a cap of one-half of one percent of the utility's aggregate customer peak demand. However, several utilities are near the overall cap for net metering already, because of the growth of PV over the last few years. Once the overall cap is reached in a specific utility service territory, the utility could refuse to allow new PV owners to net meter. At this time it is unclear what individual utilities will do once the cap is reached. If utilities do prevent additional new PV owners from net metering, this would have a serious dampening effect on the PV market, including the use of PV in new homes. AB 58 specifically exempts LADWP; it is included in this figure for illustrative purposes only.

The Committee believes that a higher net metering cap is necessary to facilitate the orderly development of PV markets and other renewable DG. Because SDG&E faces the most immediate challenge, the Committee recommends that the Legislature raise the net metering cap for San Diego Gas & Electric to 5 percent of peak demand to accommodate increased levels of PV and other renewable distributed generation in California.

[1]The Energy Commission, the California Public Utilities Commission and the California Consumer Power and Conservation Financing Authority, adopted the *Energy Action Plan* in the spring of 2003.

[2]The 2003 Energy Report relied on the loading order in laying the foundation for energy policies and decisions affecting the state required under SB 1389 (Bowen, Statutes of 2002).

[3]California Energy Commission*, 2003 Integrated Energy Policy Report*, California Energy Commission, Sacramento, CA, December 2003.

[4]*Resource, Reliability, and Environmental Concerns of Aging Power Plants,* Draft Staff White Paper, California Energy Commission, August 2004.

[5]California Energy Commission, the CPUC and CPA , *Energy Action Plan,* Spring 2003, p. 4.

[6]Utilization rates or capacity factors for the fleet of aging plants under study declined from 48 percent in 2001 to 26 percent in 2002 and 18 percent in 2003. *Resource Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements,* August 2004, p.23.

[7]California Energy Commission, *2003 Integrated Energy Policy Report*, December 2003, p. 8.

[8]Ibid.

[9]The majority of the aging power plants have several units that operate independent of each other. Depending on the system conditions, one or all of the units could be operating. Energy Commission staff initially selected 66 aging power plants totaling 17,126 MW of generating capacity of steam boiler units that were representative of units most likely to retire during the study period of now through 2008. Of these, 16 were removed from the study group for the staff's reliability analysis because 14 plants are owned by municipal utilities who have no plans to retire them before 2008. The additional plants are owned by PG&E who plans to operate Humboldt units through 2008 and Hunters Point which they plant to retire as soon as possible.

[10]*Draft Staff White Paper: Resource Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*, California Energy Commission, August 2004, p. 5.

[11]See Appendix B of the CPUC Workshop report on Resource Adequacy issued on June 15, 2004.

[12]There are two potential upgrades being considered for Path 26. Expanding the existing special protection systems (or non-hardware fixes) could increase transfer capability from 3,400 to 3,700 MW by 2005. Transfer capability could be increased to 4,400 MW with reconductoring of 500 kV lines, upgrade of 500 kV capacitors and installation of voltage support equipment.

[13]See pages 13, 14 and 15 of *Lightning Strikes Twice: California Faces the Real Risk of a Second Power Crisis*, Bay Area Economic Forum, (August, 2004)

[14]CPUC Decision 03-03-032.

[15]The feasibility of implementing dynamic pricing in California and activities being pursued is described in detail in: *Feasibility of Implementing Dynamic Pricing in California*, California Energy Commission, 400-03-020F, October 2003. A plan for increasing demand response in California is presented in: *An Action Plan to Develop More Demand Response in California's Electricity Markets*, Energy Commission, P400-02-016F, July 2002.

[16]CPUC Rulemaking 02-06-001, Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing

[17]*Upgrading California's Electric Transmission System; Issues and Actions for 2004 and Beyond*, P. 57-58; California Energy Commission, July 2004.

[18]P. 5 of D.04-07-028 of the CPUC (July 8, 2004).

[19]P. 17 of D.04-07-028 of the CPUC (July 8, 2004).

[20]See Resolution E-3888 adopted by the CPUC on August 19, 2004.
[21] California Energy Commission, December 2003, *Electricity and Natural Gas Assessment,* Sacramento, CA, p 5.

[22]See Table 3-3 and the discussion on pages 3-9 and 3-10 of PG&E's testimony in the R.04-04-003.

[23]California Energy Commission, August 2004, *Resource Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*, Draft Staff White Paper.

[24]CA ISO, January 7, 2004, Market Surveillance Committee of the CA ISO, *Opinion on Large Generator Interconnection Rule*.

[25]CPUC Decision 87-12-066 ruled that for inclusion in utility rate base future use, distribution and related transmission plant for SCE could be held only up to five years.

[26]This is largely a result of the CPUC's interpretation of Public Utilities Code section 1003(d).

[27]California Independent System Operator, "Comments at June 14, 2004 IEPR Committee Workshop," Recorded Transcripts, pp 47:7-15.

[28]*Consortium of Electric Reliability Technology Solutions. Planning for California's Future Transmission Grid: Review of Transmission System, Strategic Benefits, Planning Issues, and Policy Recommendations*. Consultant Report. Prepared for the California Energy Commission. Publication number 700-03-009, p. 28. October 2003.

[29]CA ISO Tariff Section 3.2.1.1 outlines the requirements for a need determination for economically driven projects, while Section 3.2.1.2 outlines the requirements for a need determination for reliability driven projects

[30]Mark Baldassare, July 2004, PPIC Statewide Survey: Special Survey on Californians and the Environment, Public Policy Institute of California, Sacramento, CA [http://www.ppic.org/main/pubs.asp], accessed July 24, 2004, p. 11.].

[31]Out-of-state renewable energy is also eligible to participate in the RPS.

[32]*Draft Staff White Paper: Accelerated Renewable Energy Development*, California Energy Commission, June 2004, p. 2.

[33]September 2003, Letter from Southern California Edison to the Energy Action Plan Steering Committee.

[34]*Draft Staff White Paper: Resource, Reliability, and Environmental Concerns of Aging Power Plants*, California Energy Commission, August 2004, p. 34, footnotes 4 and 5.

[35]The Western Governor's Association consists of governors from Alaska, Arizona, American Samoa, California, Colorado, Guam, Hawaii, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, North Mariana Islands, Oregon, South Dakota, Texas, Utah, Washington, Wyoming.

[36]SB 1305 requires all retail providers are required to give their customers a power content label every quarter. The retail provider must provide a forecast of the mix of energy sources purchased to serve the customer, or a default value that represents the previous years mix of used to serve customers after accounting the specific purchases by retail providers in that year. The default value is called "Net System Power" in the enabling regulations and California Mix on the label. Net System Power is determined by taking the Gross mix of power and subtracting the specific claims made by retail providers to get the "Net System Power" mix. This represents what is left over for customers that are served by retail providers that are not producing/buying energy from specific generators. The power content label is one feature of the Power Source Disclosure Program. Details can be found at http://www.energy.ca.gov/sb1305/index.html and at [http://www.energy.ca.gov/sb1305/certificates/index.html].

[37]http://www.joinarnold.com .

[38]California Energy Commission, July 2004, *Accelerated Renewable Energy Development, Prepared in Support of the 2004 Integrated Energy Policy Report Update Proceeding (03-IEP-01),* July 30, 2004. Appendix A, p A-2, Row 24. Report to the California Public Utilities Commission: Utility Procurement of Renewable Energy in 2001 and 2002, Southern California Edison, October 20, 2003.

[39]Ibid, page 25, Chapter 3, endnote 2. 2002/2003 interim procurement (reported in D04-06-014, Standard Contract and Terms decision, Appendix B, Calculation for SDG&E, SCE, PG&E's 2004 RPS Annual Procurement Target.

[40]*Staff Draft White Paper*, Appendix A, p A-2, Row 24, SCE increased renewables to 12,791

[41]September 2003, Letter from Southern California Edison to the Energy Action Plan Steering Committee.

[42]A REC represents the renewable attributes associated with one megawatt hour (MWh) of renewable-based electricity that has been generated.

[43]CPUC Decision 03-06-071, Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard, June 19, 2003.

[44]The bill states that a renewable energy credit means the following: "a certificate of proof, issued through the accounting system established by the Energy Commission, that one unit of electricity was generated by an eligible renewable energy resource and delivered to a retail seller or the Independent System Operator. The Energy Commission shall ensure that the renewable energy includes, but is not limited to, all renewable and environmental attributes associated with renewable electricity production. ... Any electricity generated by an eligible renewable energy resource attributable to the use of nonrenewable fuels, beyond a de minimum quantity, as determined by the Energy Commission, shall not result in the creation of any renewable energy credits."

[45]California Energy Commission, July 2004, *Accelerated Renewable Energy Development, Prepared in Support of the 2004 Integrated Energy Policy Report Update Proceeding (03-IEP-01),* July 30, 2004.

[46]California Energy Commission, October 2003, *Renewable Resources Development Report*, Sacramento, CA, p. 50.

[47]The research findings on wind facilities are reported in the consultant report prepared for the Energy Commission on this topic, *Developing Methods to Reduce Bird Mortality in the Altamont Pass Wind Resource Area* (500-04-052). The number of deaths of protected and endangered birds was 1.5 to 2.2 raptor fatalities/MW/year and 3.0 to 8.1 bird fatalities/MW/year.

[48]Standard offer contracts were instituted by the California Public Utilities Commission to establish prices, terms and conditions for investor-owned utility purchases from independent generators, including renewable generators, in the late 1970s and 1980s in response to the federal Public Utilities Regulatory Policy Act of 1978.

[49]California Public Utilities Commission, June 19, 2003, "Rulemaking 01-10-024, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development."

[50]CPUC Decision 04-01-050, January 22, 2004 in Utility Procurement Proceeding R01-10-024

[51]Currently, the Energy Commission's Emerging Renewables Program funds PV and small wind systems up to 30 kW in size, although solar thermal electric systems and fuel cells using renewable energy are also eligible.

[52]California Energy Commission, July 2004, *Accelerated Renewable Energy Development, Prepared in Support of the 2004 Integrated Energy Policy Report Update Proceeding (03-IEP-01).*

[53]The Self Generation Incentive Program funds systems of 30 kW to 1MW for PV, wind and other distributed generation technologies, including fuel cells, turbines, microturbines, and internal combustion engines using renewable or conventional fuel sources, except diesel.

[54]Mark Baldassare, July 2004, *PPIC Statewide Survey: Special Survey on Californians and the Environment*, Public Policy Institute of California, [http://www.ppic.org/main/pubs.asp], accessed July 24, 2004.

[55]California Energy Commission, July 2004, *Accelerated Renewable Energy Development Draft Staff White Paper*, 100-04-003, [http://www.energy.ca.gov/2004_policy_update/documents/index.html#draftwhitepapers], accessed August 6, 2004, pages 76-77.